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ELECTRICAL NETWORKS AND ECONOMIES OF LOAD DENSITY

Doctoral Dissertation

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Abstract

The objective of this thesis is to determine electrical network cost and cost structure depending on load density. Load density together with a defined customer mix directly determines the supply task, i.e., the number of connection points and their density in a geographical area as well as their load profiles. Load density indirectly determines the construction conditions since higher load density means a higher building efficiency which in turn leads to restrictions in land use and more strict structural requirements.

The applied methodology adopts features from several engineering-economic approaches with the three basic steps: (1) Description of the supply task including relevant characteristics of the service area. (2) Network generation. Linear approximations of cost functions for lines and substations are used together with geometrical models of symmetrical and homogeneous load dispersion to determine optimal substation spacings. (3) Monetary assessment of the generated asset structure including operational and maintenance costs. The cost-effects of different external cost-drivers are incorporated into the applied cost functions. All network levels from low voltage connections up to EHV substations are included. Additionally, reliability indices are determined for the model network sample feeders with different mitigation strategies. Actual substation service areas are used as references to the calculated results. Additionally, based on the connection point data of these reference substation areas, another reference medium voltage network is created using an optimization algorithm developed at Helsinki University of Technology, Department of Electrical Engineering.

Using the model network approach, cost is determined for networks in rural, suburban, urban and urban core zones. The cost structure and level varies from zone to zone depending on the allowed equipment, share of open space and customer mix. When moving towards the highest load densities in urban and urban core areas, the cost lowering caused by higher connection point density is attenuated due to the higher unit cost of equipment.

The created analytic and geometric network model, even with massive simplifications, is proven suitable for estimating the network volume and cost for different zones and load densities. The applied methodology forms a qualified framework for further development of the model network approach.

Keywords   transmission and distribution network, load density, cost, cost structure, cost drivers, external factors

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Tiivistelmä

Väitöstyön tarkoituksena on määrittää sähköverkon kustannusrakenteen ja -tason riippuvuus kuormitustiheydestä. Kuormitustiheys yhdessä asiakasrakenteen kanssa määrää suoraan sähkönjakelutehtävän eli liittymispisteiden lukumäärän maantieteellisellä alueella sekä liittymien kuormitusprofiilit. Kuormitustiheys määrittää epäsuorasti rakentamisympäristön, koska suuri kuormitustiheys merkitsee suurta rakentamistehokkuutta, mikä puolestaan johtaa rajoitteisiin maankäytössä ja korkeampiin rakenteellisiin vaatimuksiin.

Sovelletussa tutkimusmetodissa on piirteitä useista teknis-taloudellisista menetelmistä ja siinä on kolme perusvaihetta: (1) Sähkönjakelutehtävän kuvaus mukaan lukien jakelualueen ympäristötekijät. (2) Verkon luominen; syöttöasemien optimaalinen etäisyys määritellään käyttäen johdoille ja asemille linearisoituja kustannusfunktioita ja kuormapisteiden oletetaan jakautuvan tasavälein ja symmetrisesti. (3) Luodun sähköverkon kustannusten määrittely mukaan lukien käyttö- ja kunnossapitokustannukset. Ulkoiset kustannuksia aiheuttavat tekijät on mallinnettu käytettyihin kustannusfunktioihin. Analyysi käsittää kaikki verkkotasot pienjänniteliittymistä 400 kV sähköasemiin. Malliverkkojen tyypillisille keskijännitejohtolähdöille on laskettu myös luotettavuusindeksit erilaisilla käyttövarmuutta parantavilla vaihtoehdoilla. Todellisten sähköasemien jakelualueiden verkkoja käytetään vertailukohtana lasketuille tuloksille. Käyttäen vertailusähköasemien todellisia muuntamopisteitä on lisäksi luotu referenssikeskijänniteverkkoja Teknillisen korkeakoulun Sähkötekniikan laitoksella kehitetyllä optimointialgoritmilla.

Malliverkoilla on laskettu kustannukset maaseutu-, esikaupunki- ja kaupunkiympäristöissä sekä suurkaupungin ydinkeskustaolosuhteissa. Kustannusrakenteet ja -tasot ovat erilaisia eri ympäristöissä riippuen käytettävissä olevasta komponenttivalikoimasta, kuormattomien alueiden määrästä ja asiakasrakenteesta. Kaupungeissa ja niiden ydinkeskustoissa suuresta kuormitus- ja liittymispistetiheydestä koituva kustannushyöty pienenee, koska siellä on käytettävä yksikkökustannuksiltaan kalliimpia komponentteja.

Vaikka kehitetty analyyttinen ja geometrinen verkkomalli sisältää suuria yksinkertaistuksia, osoittautui se silti soveltuvaksi verkkovolyymin ja kustannusten analysointiin erilaisissa toimintaympäristöissä ja erilaisilla kuormitustiheyksillä. Sovellettu metodi voi siten muodostaa lähtökohdan malliverkkomenetelmän jatkokehitykselle.

Asiasanat siirtoverkko, jakeluverkko, kuormitustiheys, kustannus, kustannusrakenne, kustannusajurit, ulkoiset tekijät

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PREFACE

The subject of this thesis arose from the first network evaluation efforts for regulatory purposes in the year 2002. At that time it was discovered that there was no research based knowledge of the actual effects of different cost drivers in metropolitan city conditions. Since the only source of that knowledge in our country was we who operated the electricity distribution network in this environment, we decided to carry out a study around this subject and document it in the form of a doctoral thesis.

I would like to express my gratitude to my employer, Helen Electricity Network Ltd, who has given me the opportunity to perform this study as a company project. I would especially like to thank my superiors Risto Harjanne and Jari Lintuvuori for their full support and encouragement. Special thanks go to my fellow doctoral student Jussi Palola who has tirelessly helped me in every possible way during the whole process. I also thank Antti Rautiainen who provided the network data. Thanks to all other colleagues for their contributions and conversations.

During this project I have had excellent co-operation with the specialists and managers of Kainuun Sähköverkko Oy. I thank Jussi Niskanen, Paula Ala-Nojonen, Jouni Huusko and Seppo Mäkelä for providing me with essential data and the coverage of rural network aspects.

At Helsinki University of Technology Professor Matti Lehtonen supervised my work. I am very grateful to him for his guidance and collaboration. Dr. John Millar deserves great thanks for creating and engineering the optimization algorithm used to generate reference networks. Furthermore, I appreciate him for taking the burden of revising the language of the manuscript. I thank Dr. Pirjo Heine for counselling me on the practical issues of thesis publication. I would also like to thank Professor Erkki Lakervi, who helped me at the early stages to specify the objective of this study.

Finally, I would like to thank my nearest ones, my wife Anne and my parents, for their love and support.

Porvoo, November 2008

Markku Hyvärinen

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LIST OF ACRONYMS AND SYMBOLS

a	year
A	area
AA II plus	Associations' Agreement II plus (VV II plus in German)
AEF	Average Energy Factor
AGRI	Agriculture and Household (composite user group)
AH	Apartment block (user group)
AIL	Air Insulated Line
AIS	Air Insulated Switchgear
BnetzA	The German Federal Network Agency
C	general symbol for cost
c	cent = one euro / 100
CR	network yearly rent
CAIDI	Customer Average Interruption Duration Index
capex	Capital Expenses
CBD	Commercial Business District
CBS	Intermediate circuit breakers along the feeder
CCDF	Composite Customer Damage Function
CCF	Comprehensive Cost Function
CD	Customer Density
CIC	Customer Interruption Cost
CPD	Connection Point Density
DAR	Delayed Automatic Reclosure
DBCP	Distance Between Connection Points
DBEHVS	Distance Between Extra High Voltage Stations
DBSS	Distance Between Substations (HV/MV)
DBTS	Distance Between Transformer Stations (MV/LV)
DC	Density of Customers (length of line per customer) in NPAM
DEA	Data Envelopment Analysis
DF	Discount factor
DG	Distributed Generation
DNO	Distribution Network Operator
DSM	Demand Side Management
€	euro = 100 cents
e	building efficiency

E	energy
ED	Energy Density
EEA	Engineering Economic Analysis or Engineering Economic Approach
EF COMP	Earth fault current compensation
EFI	The Norwegian Electricity Distribution Research Institute
EHV	Extra High Voltage
EMA	Energy Market Authority (in Finland)
ENS	Energy Not Supplied
Eq.	Equation
EUR	euro = 100 cents
Eurelectric	Union of European Electricity Industry
f	fixed cost parameter
FAR	Floor Area Ratio
g	growth rate
GIS	Gas Insulated Switchgear
GPS	Global Positioning System
h	unit price
HUT	Helsinki University of Technology
HV	High Voltage
i	interest rate
ICT	Information and Communications Technology
INDC	Industry (composite user group)
k	general symbol for a constant
k_{1r}, k_{2r}	Velander constants of the user group r
L	Length (of line)
LCC	Life Cycle Cost
LD	Power Density
LL	Line Length (of a feeder or feeder system)
LLAF	Line Length Adjustment Factor
LV	Low Voltage
km	kilometre
kV	kilo-Volt
kVA	kilo-Volt-Ampere
kW	kilo-Watt
kWh	kilo-Watt-hours
m	number of segments

MV	Medium Voltage
MVA	Mega-Volt-Ampere
MW	Mega-Watt
N,n	number of something
NC	Number of Customers
NCP	Number of Connection Points
NPAM	Network Performance Assessment Model
Ofgem	The Office of Gas and Electricity Markets, the regulator in Great Britain
OHL	Overhead Line
O&M	Operation and Maintenance
opex	Operational Expenses
P	active power
PW	Present Worth
PWF	Present Worth Factor
QA	Quality Adjustment (in NPAM)
Q	bi-weekly index
q	hourly index
r	radius, mean time to repair, outage time
R	Resistance
R^2	correlation factor
R21…R23	rural reference substation areas
RAR	Rapid Automatic Reclosure
RD	Road Network Density
REF	Reference point for a feeder, a feeder without any mitigation actions
REM FAULT IND	Remotely read fault indicators
REM SECT	Remotely operated sectionalizers
RES	Reserve connections
RH	Row-House (user group)
RHEH	Row-House with Electrical Heating (user group)
RMU	Ring Main Unit
RNA	Reference Network Analysis
ROI	return on investment
RWTH	Rheinisch-Westfaelische Technische Hochschule Aachen
s	distance (or line length)
S	apparent power
SAIDI	System Average Interruption Duration Index

SAIFI	System Average Interruption Frequency Index
SC	Short Circuit
SCDF	Sector Customer Damage Function
SECT	Manually operated sectionalizers
SERVC	Public and Commercial Services (composite user group)
SFA	Stochastic Frontier Analysis
SFH	Single-Family House (user group)
SFHEH	Single-Family House with Electrical Heating (user group)
SLYIND95	load profile series by the Association of Finnish Electric Utilities
t	time, future year
T	time period, life cycle
T&D	Transmission and Distribution
TFH	Two-Family House (user group)
TFHEH	Two-Family House with Electrical Heating (user group)
TOTEX	Total Expenses
U	unavailability, outage time
U11…U21	urban reference substation areas
UK	United Kingdom
v	variable cost parameter
VAD	the Spanish acronym for Valor Agregado de Distribución, distribution added value
vd	voltage drop
VDN	Verband der Netzbetreiber, German Association of Electric Network Operators
VNR	the Spanish acronym for Valor Nuevo de Reemplazo, new replacement value
VOH	optimization algorithm named after the Finnish acronym of the project
VV II plus	Verbändevereinbarung II plus (AA II plus in English)
w	per unit share of the total annual energy
W	annual energy
x	x-coordinate
X	reactance
y	y-coordinate

Greek letters

α	participation factor
β	$\theta/2$ = half of the MV feeder service area sector angle
γ	auxiliary variable
δ	auxiliary variable
ε	share of the total energy
η	auxiliary variable
θ	MV feeder service area sector angle
λ	failure rate
ρ	per unit reserve power capacity requirement
ω	share of open space

Subscripts

a	annual
ave	average
c	customer interruption (cost)
CP	Connection Point
cpr	customers per connection
EHV	Extra High Voltage
EHVS	Extra High Voltage Station
f	repair (cost)
F	feeder
FLV	Low Voltage Feeder
FMV	Medium Voltage Feeder
h	hourly value
HV	High Voltage
i	interruption, component index
INDCMV	composite user group of industrial MV customers
inv	investment
j	subarea, segment of the service area
loss	losses
kN	nominal load losses
LV	Low Voltage
m	maintenance
max	maximum
min	minimum

MV	Medium Voltage
MVBays	Medium Voltage Bays at the HV/MV substation
MVC	Medium Voltage Customers
N	nominal
NA	number of connections in an area
ON	nominal no-load losses
O&M	Operation and Maintenance
out	outage
p	peak
pk	price of load losses
pl	power losses
p0	price of no-load losses
PW	present worth
r	user group
s	series system (radial system)
sw	switch
SA	Substation Area
SERVCMV	composite user group of commercial and public service MV customers
SS	Substation (HV/MV station)
T	transmission distance
tot	total
TS	Transformer Station (MV/LV station)
TSA	Transformer Station Area
wk	energy of load losses
w0	energy of no-load losses

1 INTRODUCTION

1.1 The role of electrical networks

Electricity has many special features compared to other commodities. It is nonstorable, and thus nonportable, in large amounts. Therefore, its delivery from production plants to customers requires a fixed physical transmission network with a continuous flow of electricity. Similar networks are needed for water, gas and heat supply and sewerage. The geographical scope of these networks, however, may be quite dissimilar. Water supply and sewerage systems are local or regional and unconnected to corresponding neighbouring systems. Buildings may have their own heating systems independent of the fixed networks. Gas networks usually do not cover the entire area of potential load. Road networks and electrical networks are in this sense different from the others, because they cover the whole geographical area of human activity, each with a single interconnected system. Technically it is possible to generate electrical energy locally using stand-alone apparatus, but in European countries this is economical only in extreme circumstances. The evolution of power systems during the 20th century has led to large nation-wide or continent-wide interconnected systems where load diversity (non-coincidence of individual loads) and distributed energy resources are utilized to achieve scale economies. The advantages are materialized in shared and dispersed generation reserves, larger generating units in proximity to primary energy resources, higher transmission voltages and the possibility of competition between generators. The last-mentioned aspect means that electrical networks are a prerequisite for electricity markets.

A common feature for most of the infrastructure networks is that it is not economically or even physically possible to build and operate parallel competing networks: these networks constitute natural monopolies. In order to create functioning electricity markets, the formerly vertically integrated power supply industry has been restructured. This has led to unbundling of the system into two parts: a liberalized competitive part comprising generation, wholesale trading, retail trading and consumption, and a reregulated monopolistic part comprising transmission and distribution. The competitive element for monopolies is implemented in two ways: through indirect competition, which has led to expanding markets for service-providers (engineering, maintenance, operations), and through different regulatory models.

Regulators supervise the reasonableness of network pricing, the quality of supply and the efficiency of network operators. Regulation models normally include some form of efficiency benchmarking. This is also the case in Finland, where the applied rate-of-return regulation provides sufficient incentives for capacity expansion, but does not give incentives for cost reduction. Incentive regulation relies on the information advantages and profit motives of companies. Distribution companies themselves have the best knowledge of their opportunities to cut costs and incentive regulation encourages them to carry out the possible cost reductions.[1] In the assessment of the relative efficiency of distribution operators, a company's technical and cost efficiency is measured against a reference performance. Since these companies operate in different environmental circumstances, it is crucial to distinguish between inefficiency and exogenous heterogeneity that influences the costs. What makes the task even more challenging is the fact that network companies themselves do not have homogeneous supply areas, but are operating in geographically diverse territories. While the inefficiency estimates can have significant financial consequences for the network operators, their reliability is crucial for a balanced regulation system. It is also essential for the network operator to comprehend what causes the inefficiency.[2] Altogether, regulation, comparison of networks and improvement of the efficiency require proper understanding and systematic evaluation of the relevant cost-drivers.

1.2 The composition of the network cost

The share of electricity distribution networks in the total infrastructure cost is relatively small. A study [3] concerning the Uusimaa Province in southern Finland shows that the construction and maintenance costs of buildings are dominant in all types of areas. The energy supply infrastructure investments, including electrical and district heating systems, make up at the most less than 5 % of the total investment sum. The portion is even smaller if life cycle cost is considered. In urban areas where there is shortage of space, the share is around 1 % (Table 1). The conclusion is that the energy infrastructure overall, the electricity distribution network included, has no significant impact on community infrastructure. Even great variations in costs of networks may not have a notable effect on community planning.

Table 1*. Division of infrastructure costs in Uusimaa Province, southern Finland.* [3]

		New urban areas	**Developing urban areas**	**Villages, rural areas**
Investment		€/floor-m^2	€/floor-m^2	€/floor-m^2
Dwellings, offices, commercial and industrial premices		buildings: 1 670 … 1 100 €/floor-m2 land: 330 … 100 €/floor-m2		
Public infrastructure	road and street network	50	40	160
	water supply	20	16	64
	energy supply	20	16	64
Operation and Maintenance		€/floor-m^2,year	€/floor-m^2,year	€/floor-m^2,year
Dwellings		22,0	23,0	23,0
Offices, commercial and industrial premices		44,0	44,0	44,0
Public infrastructure	road and street network	1,3	1,1	4,4
	water supply	0,5	0,4	1,6
	energy supply	0,4	0,3	1,2

Moreover, electrical networks are essential facilities that should be both accessible and affordable to all citizens. Within their geographical territories, the licensed network operators must guarantee entrance of generators and consumers to the electricity market, independent of the external conditions.

The fundamental setting is that both the supply task and the external circumstances are basically determined exogenously for each network operator.

In order to compare network operators and their effectiveness, the division of costs into the following three categories is necessary:

- the minimal network infrastructure cost needed to fulfil the basic supply task
- cost-rises and cost-drops due to external conditions ('structural characteristics')
- additional cost influencable by the network operator, e.g., the cost for quality improvement

A series of four figures (Figure 1, for explanations see the text) illustrates the exogenous and endogenous factors affecting the network cost:

A. The minimum cost due to the electrical connection between the supply point and the load point to fulfil the basic supply task including the obligatory requirements for voltage quality, safety and other authority regulations. The network operator does not have an influence on customer location, demand or type of load. If all external conditions were omitted, this basic task could be fulfilled by building a minimum cost straight line between the supply and load points. Here we assume that the existing supply point does have enough capacity to feed the new load point. (Figure 1 A)

B. Additional cost due to local external circumstances such as topography and other factors limiting the free use of land. The network operator does not have a significant influence on these factors either, at least not in the short run. They affect the network cost through extended line lengths and restrictions on using certain structural types of equipment. The impact of the network operator is to proficiently find the shortest or cost-minimal route and structurally cost-effective solutions that are suited to the environment. (Figure 1 B)

C. Reduced cost due to the proximity of customers with each other (customer or connection point density). Common supplying infrastructure can serve several customers if they are within an appropriate 'electrical reach'. As customer locations cannot be influenced, this is also an exogenous factor. (Figure 1 C)

D. Other factors that are degrees of freedom in network design, especially the choice of reliability level. Society's substantial dependency on electrical energy and continuity of supply will possibly shift reliability – at least the minimum requirements for it, set exogenously by the authorities - to become part of the basic supply task. Within the set constraints, quality of supply will then be controlled by incentive regulation mechanisms and thus it will remain as a partly endogenous factor. To reduce restoration times, reserve connections (or local back-up power) are needed. The length of the reserve lines depends upon connection density. Therefore, although an extra cost, the level of that cost is reduced in areas of high load density. The required reserve capacity affects equipment ratings, which again is a cost-raising factor. (Figure 1 D)

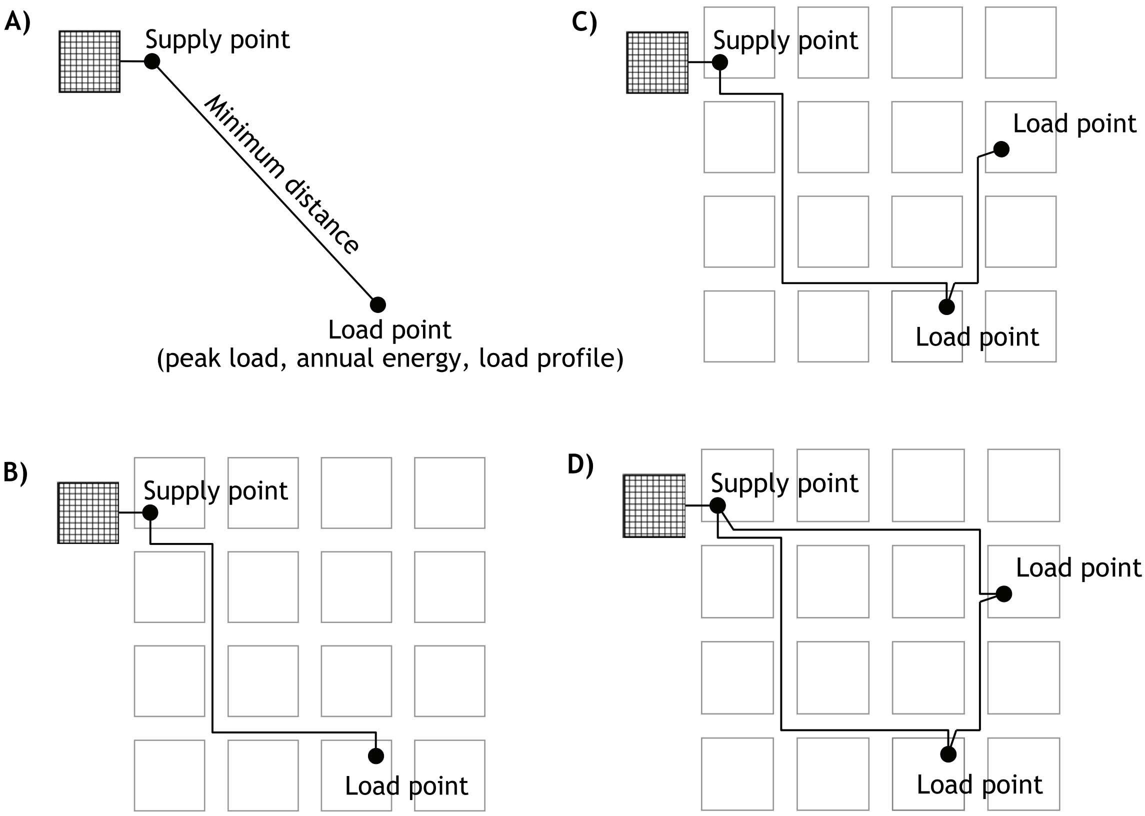


***Figure 1**. A simplified example of the composition of the network cost (see text for explanations).*

As we can see, there are both cost-raising and cost-reducing factors which have opposing effects on the total network cost. The outcome is that modelling and evaluation of the network cost is not a straight-forward exercise.

In addition to the before-mentioned factors, there are cost effects due to the historical development of the network. The factors which appear as uncertainties at the planning stage (load growth, location of generating plants, land use development, technology development) may in the course of time lead to non-ideal solutions measured by today's standards and greenfield solutions. To some extent this must be accepted, since the lifetimes of equipment and structures are measured in decades.

1.3 Research objective

Network companies do not operate in similar conditions. Dissimilarity in exogenous factors leads to different cost structures and cost levels. These factors have to be considered when comparing companies with each other. As such they are separately considered in the estimation of a cost function in parametric methods. In non-parametric methods it is possible to use the so-called environmental factors if necessary, in addition to the input and output parameters. The selection of these indicators is successful if companies operating in similar conditions can be recognized and, on the other hand, dissimilar companies are segregated [4]. During the development of balanced benchmarking models, a number of parameters have been tested and adapted, see for instance [5]. However, it has been a frequent topic of discussion whether the chosen individual parameters or their combinations fully describe all the relevant conditions. This has been especially recognized concerning urban environments [2]. At the same time, verification of the benchmarking model is typically possible to a limited extent. This particularly applies to Data Envelopment Analysis (DEA), which is generally the preferred regulatory benchmarking methodology in practice.

As load density – measured by energy, peak demand, population, customer or connection point density – increases, the cost per customer and the cost per transmitted electric energy decreases, on condition that the construction costs of the network and the reliability target level remain the same. This is resulting from the shorter lines needed and the economy of scale in utilizing larger unit sizes (see 1.2). However, the structural conditions of the supply area have an evident influence on the network component unit costs. Diverse factors, such as the higher cost of trenching, higher demands for aesthetics and reliability, etc., cancel at least part of the benefits brought by the higher load density. Unique structural characteristics are prevailing in city cores, where the electrical lines must be enclosed in duct banks routed under the streets and the substations must be built in underground vaults or inside buildings. Ultimately this creates an economic situation dominated by the construction costs of the underground structures. Representing the other extreme are the sparsely populated rural areas where small point loads must be fed by very long overhead line feeders. The economies of load density thus have an effect in both directions, cost-increasing and cost-reducing. The effect of these contradictory factors is presumably nonlinear and, consequently, the resulting distribution system cost is not unambiguous.

Although the diverse impacts of the above described economies of density are rather well recognized in broad outline, analytical cost-driver evaluation work has been rare. The studies have usually been limited to one component group or some restricted part of the system. In Finnish conditions, where there is only one metropolitan-like area, the extreme urban aspects have been peculiarities as far as the benchmarking of networks is concerned.

The objective of this thesis is to quantify the effects of exogenous factors on the network cost, particularly the effect of load density and other factors in close relation to it. Although there are specific issues concerning the urban areas with highest load densities, the whole density-range from sparsely populated rural areas to crowded city-cores is covered.

1.4 Literature review

In recent years, the need to understand the cost-drivers of electrical networks springs from the development of regulation and benchmarking models. Therefore, plenty of benchmarking studies and reports can be found from around the world including Finland. They have been reviewed from the point of view of treatment of cost-drivers and environmental factors. Secondly, an engineering-economic approach of the same subject has been surveyed. Finally, a brief look at a research area interlinking with the subject, concerning community structure and economies of scale in urban and metropolitan areas, has been taken.

Econometric and statistical approaches

In Finland, the application of Data Envelopment Analysis was studied in 1999[6] and 2000[4], and the model specifications were first introduced in 2000. At that stage the environmental factors were also analysed. A group of industry experts played a key role in the selection of factors and indicators that were used to characterize the supply task. They especially contributed to exploring the environmental factors that affect the cost of companies.[4,7] In addition to the more or less universal indicators for geographical dispersion of customers, number of customers, consumption characteristics and quality of supply, the specific natural conditions in Finland were analyzed. These were winter conditions, forest cover and insular areas. Forest cover in square kilometres in the distribution area was found to be a reasonable proxy for increased construction costs, but as forests can be avoided to at least some extent, this is partly an endogenous factor. Average snow depth is a proxy for all the conditions linked to winter conditions, but in the lack of a natural scale, the usefulness of this factor was considered limited. No useful numerical indicator could be found for insular conditions. Definition of urbanization was felt to be problematic. The optimal size of a town was approximated to be around 20 000 citizens, which is far less than the size of the largest cities in Finland. It was only possible to make a statement that the city cores of the largest cities have to be evaluated separately. Therefore, no special indicator was derived for urbanization either. It was assumed that other factors such as the geographical dispersion of customers (measured by the total line length) and the number of customers, will cover this aspect as well. The final model included operational expenditure as the input; distributed energy and quality as the outputs; and geographical dispersion of customers and number of customers as environmental factors. Quality of supply was later removed from the model. Quality of supply, through customer interruption cost, will be taken into account in the present model as part of the total cost. Also, parallel to the DEA method, Stochastic Frontier Analysis (SFA) will be used as a benchmarking tool. In the SFA model there will be a rough division of distribution lines into urban and rural lines [8,9]. Given the lack of multiple large cities in Finland, statistical comparative studies of ultimate urban conditions in city-cores is not feasible.

To gather experience on wider international distribution network benchmarking, the Union of the Electricity Industry (Eurelectric) carried out a pan-European benchmarking of electricity distribution companies during the spring and summer of 2002. Altogether 48 distribution companies from 22 European countries were benchmarked. Among other results the final report[2] presents some revealing points from the project including the main drivers of uncertainty. One of them was caused due to the comparison of urban and non-urban operations. For this reason, an attempt was made to find an objective correction for 'city surplus cost', such as the amount of solidified surface, but this was not possible. Instead, the surplus cost was found to correlate somewhat to the customer density given as the number of customers per kilometre of low voltage line. The correction was also included in the baseline benchmark. This approximation produced a reasonable benchmark, but was supposed to be unfavourable to some companies as it assumes that the structure of the companies and their urban environment is similar. The apparent correlation between surplus costs and customer density is non-linear, which will slightly distort the benchmark of companies that serve large cities as well as some urban areas. The conclusion was that the surplus cost of city operations will be a main cause for uncertainty in national as well as international benchmarking. Other external conditions that were analysed were 'grids in forests' and 'grids in mountains', but since either the variation of the surplus cost was too great or the sample was too limited, correction was not included in the baseline benchmark for either of these factors. Contrary to expectations, there was no significant correlation between operating costs and reliability in the sample. Although the data quality on reliability was poorer than the financial and physical data, it was also assumed that reliability depends more on capital spending than on operations.

In Norway[10], in the development phase of the DEA model, several environmental constraints were tested using a so-called stepwise approach. The stepwise approach is based on the idea to test whether adding a new factor to a DEA model causes a statistically significant change in the efficiency scores. This approach was also used in the development of the Finnish model[4,7]. Environmental constraints were described as distance, climatic and corrosion indices. The distance index was defined as the travelling time from each basic district in the national census to the municipal centre, using the population-weighed average for all basic districts multiplied by the number of customers. By this definition the distance index includes both distance and travelling difficulties in one variable. The corrosion index is a variable in the range from 1.0 to 4.0 based on 40 years per the actual depreciation period, where the depreciation period is estimated by the Norwegian Electricity Distribution Research Institute (EFI). The corrosion index multiplied by the distance index is an index that covers the length of lines that are exposed to corrosion. The climatic index is the absolute value of average temperature in the three coldest days of each year divided by the sum of the temperatures for all days of frost. The climatic index multiplied by the number of customers is an index of the need for peak capacity compared to average capacity. The distance index was included in the model, while the others proved to be proxied by the other parameters that were included, namely the number of customers, energy delivered, labour hours, energy loss, capital and goods and services.

London Economics prepared a report[11,12] on efficiency and benchmarking of the distribution businesses in New South Wales, Australia. As part of the report, a statistical analysis was undertaken that tested to what extent environment variables explained the differences in DEA scores. The tested factors included customer density, load density, system loading, and customer mix. This statistical analysis indicated that the mix of customers (e.g. the proportion of domestic customers) and network configuration mix (e.g. the proportion of overhead network) have a significant influence on the DEA score. Customer density (customers/square kilometre of service area) was found not to have a significant influence on the DEA using the statistical analysis, but this was assumed to be explained by the fact that this operating environment variable was already directly accounted for in the model. Network reliability was also unable to significantly explain the differences in the DEA scores. However, this result may reflect the limited sample size over which this reliability analysis was conducted, since it was not possible to obtain consistent reliability data for all observations in the DEA analysis.

A more recent benchmarking report from Australia[13,14] has proposed an analytical framework based on cost of production theory. Fourteen of Australia's electricity distribution networks are included in this study. The sample contains a mix of network types, high and low density, and large industrial and small customers. The report identifies major cost drivers and assesses the varying impact of these factors on comparative costs. It demonstrates that the operating environment of distribution networks can have a substantial influence on comparative cost. Following a quantitative assessment of a large range of possible factors, two major conditions were identified in distribution networks: connection density, measured as the number of connections or capacity provided per kilometre of line length, and customer class, measured as the average level of energy consumption for end-users. Density, whether measured as connections, capacity, or energy flows per kilometre of network length, was the single most significant cost driver for distribution networks. At the transmission level, energy density was found to be a major determinant of investments. It was further discovered that the powerful influence of connection density effectively separates Australia's networks into four groups for purposes of cost comparisons: CBD (Commercial Business District), urban, mixed (mainly state-wide networks) and rural. Similar analysis for more numerous and diverse New Zealand networks had revealed strong correlation as well. Concerning the urban networks or large industrial customers, the higher cost of servicing was obscuring some scale benefits. Regression analysis of a much larger sample of US networks had indicated that scale benefits were present although they were not very significant. Another finding was a strong linkage between three factors: connection density, assets per kilometre, and total costs per kilometre. This was explained by connection density almost directly determining the demand and use of network assets, meaning that the operating expenses (opex) and the capital expenses (capex) are influenced strongly by the same cost driver.

In a report for Ofgem[15] three measures of topography and climate were considered: the percentage of the network underground (which was seen as a proxy for urbanisation or terrain), customer density and energy density. Because all three measures were reasonably highly correlated, it was suggested that the variable to be used as a cost driver was customer density. Further, a single composite scale variable was considered sufficient, the composite consisting of the weighted variables of customer density, customer mix and percentage losses. This way the UK regulator could adopt a simple regression model with one dependent (operating costs) and one independent variable (the composite output) to increase the robustness of results.

Engineering-economic approach

Engineering-economic analysis (EEA) is based on the comparison of the network's or company's performance against that of an artificially constructed optimal network or company (benchmark). This approach removes the need for a large benchmarking sample and can in principle be applied to the case of a single company. Network models are based on an engineering approach and cost functions implanted in the model construction. This way, they simulate the network planning process. The application of EEA to distribution involves the following steps: (1) examining the key features of each distribution region, including the terrain and the dispersion of customers, (2) designing a least cost network to serve these customers, given the physical features; and (3) estimating the cost of building and maintaining this least cost network.[15,16]

▪ Chile [16, 17, 18, 19]

In Chile, reference network models have played an important role in the benchmark regulatory process for more than 20 years. Starting from the existing network configuration and assets, a model company including not only the physical network, but also customer service, administration and management, is constructed and dimensioned. Groups of companies of similar characteristics are compared with a model company, identified through typical network zones (e.g., high density, urban, semi-rural and rural). The network model determines the cost that would be incurred by an efficient company supplying electricity to a mixture of zones corresponding to the actual company. Quality is not considered in the optimisation process. Also, heterogeneous companies are compared in an integrated manner, with an assessment of general industry performance. The costs and their allocation to three fields (high voltage, low voltage and customers) are determined. Finally, the VAD (distribution added value, in its Spanish acronym for Valor Agregado de Distribución) and the corresponding adjustment indices to be used in the following regulation period are determined, together with the identification of special circumstances.

The annual investment costs are calculated considering the new replacement value (VNR, the Spanish acronym for Valor Nuevo de Reemplazo), the facilities adapted to the demand, and a discount rate equal to a real 10% per year. The calculations are carried out for a specific number of typical distribution areas defined by the National Energy Commission, with a previous consultation with the firms. The process to determine the VNR has the objective of calculating the "cost to renew all the works, facilities, and physical goods dedicated to provide the distribution service in the respective concessions." The concept of VNR used by the Chilean legislation to be applied to distribution activities has been a hybrid between the substitution and replacements costs.

The law requires two independent optimization studies forming the basis for determining the company's income. One by the distribution company and a second one done by the Chilean regulator. The results of these two studies must be averaged, considering a weight of two thirds for the regulator and one third for the distribution company. The models used for the analysis are not public, but it is evident that there is no common optimization methodology. Different methodologies employed by consultants have led to conflicting results. A main area of divergence is that of the optimal management cost, in the absence of mathematical models to deal with this matter in engineering management.

▪ Spain [20, 21, 22]

In Spain, a reference network model has been developed to analyse the technical efficiency of the networks. This model has been developed in multiple forms by the distribution companies themselves and by universities. The purpose of this tool is to model the minimum-cost (including investments, operating and maintenance costs, and technical losses) network to serve demand and which is in compliance with statutory service quality constraints. The reference network model is used together with benchmarking techniques based on the results obtained from cost accounting. The results of the service quality levels will form part of the remuneration base, creating incentives for the distribution companies to attain higher quality levels.

Since the reference network tool results are intended to be used as an accurate benchmark for real networks, emphasis has been put into the accuracy of the optimization model. To achieve this, fore mostly the distribution service areas should be modelled accurately. This includes customers' GPS coordinates, contracted powers, annual energy consumptions and peak coincidence factors. Distribution service areas are modelled in considerable detail, using parameters associated with the identification of settlements and the selection of aerial or underground network areas within settlements. For the different operations, maintenance and investment cost, the model makes a series of corrections to account for regional differences: corrections are introduced for such factors as ice, salt level, precipitation, altitude, indemnifications, right of way and land access, staff costs and city size. The impact of city size is to lower investment costs in small cities by 10% and to increase it in large cities by 10%. Historical network voltage levels are used, because the replacement costs of existing assets are uneconomical. In the optimization process, the reserve factors and quality service indices used to size assets are considered as key issues. A standardized equipment database (lines, cables, distribution transformers, distribution substations, protective devices, etc.) is used in the design of the network. As these parameters have a great impact on network sizing, it is thought that they should be set by the regulator.

The suggested fashion of using the reference network tool is to determine maladjustment percentages for high voltage fixed assets, medium and low voltage fixed assets and quality level. The maladjustment for high voltage fixed assets is calculated by comparing the modelled and the actual high voltage network for each company and area. For medium and low voltage distribution networks, two calculations are made for each company and area; one uses the actual location of the transformer stations as pertinent data, and the other calculation does not pinpoint them. Similar calculations are carried out considering quality levels. The maladjustment percentages would then be gradually reduced according to targets set by the regulator.

▪ Sweden [22, 23, 24]

Sweden has applied a reference network model as the main regulatory tool by introducing an approach called the Network Performance Assessment Model (NPAM). The model has been developed since 1998 by the regulatory agency. In the model, a reference utility is created by first generating a fictitious reference network for each distribution area given the input data. This reference network is then valued using standard cost functions in the model, hence creating the reference utility used as a hypothetical cost-efficient benchmark company. Power quality is included in NPAM calculations through an evaluation of actual and expected interruption costs. The end-result of the model is the reasonable level of revenue, called network performance, which reflects the price level customers are willing to pay. This network performance is then compared to the aggregated revenues of the distribution network operator. Companies with unreasonable revenues could be selected for further investigations.

One of the basic features of NPAM is that the model is founded on the density of clients measured as length of line per subscriber (which is actually a one-dimensional measure of *sparsity* of customers). To avoid the importing of topographical information to the model and employing complicated routing algorithms, certain adjustment factors are used to correct the straight line distances between two points to depict realistic line lengths. These factors also take into account the length of reserve connections.

While the Chilean and Spanish models are based on zones, the NPAM describes the environment with continuous density functions. The model measures the density of clients at each node in the grid. As experiences have shown a strong relationship between the investment and the subscriber density, the NPAM uses standard cost functions continuously depending on this density. The mathematical description of density functions is defined through a modified *tanh(x)* function:

$$C = \left(k_1 + k_2 \cdot \tanh\left(k_3 \cdot \left(DC - k_4\right)\right)\right)^{k_0} \qquad \textbf{\textit{Eq. 1}}$$

where

C = cost
$k_0 \ldots k_4$ = constants
DC = density of customers (=length of line per customer)

This cost function, with different constants, is used to calculate the costs of lines, transformers, land, network losses, outage cost parameters, reserve capacity needed, expected outage costs and a geometrical adjustment factor.

Network performance is calculated based on the repurchase value of the fictive network. The repurchase value of the fictive network is based on the number of components in the fictive network and the unit costs of components, determined with the above described cost function. Capital cost is calculated with a certain interest rate, which consists of risk-free interest and a risk supplement, and 40 years depreciation time. Operational costs are one percent of repurchase value for lines and two percent for transformers. Customer specific costs are fixed and depend only on the voltage level of the customer. Quality adjustment (QA) in NPAM is calculated with the equation:

$$QA = \textit{Cost of reserve capacity - (Reported outage costs - Expected outage costs)} \qquad \textbf{\textit{Eq. 2}}$$

and thus the quality level is directly linked to the network structure via the assets forming the reserve connections.

The NPAM method compromises between accuracy (optimality) and transparency. The final decision by the developers was to disregard optimization. Experience has shown that the algorithms create networks that are in any case much more efficient than the actual networks. Thus it has been considered that the extra efficiency of the optimized networks is not necessary. The reference network is unambiguously defined through public network definitions and the parameter set. The assessment software is distributed for free to all companies.

▪ Austria [16]

The Austrian regulator has used a model network approach to analyse the relationship between the different supply tasks and network assets to identify significant cost-drivers for the complexity of the operating environment and to identify the functional relationship between cost-drivers and costs. Their model network analysis showed that there is no single parameter to explain the cost of the network operator. Especially, the load density (load/km^2) and connection density (number of connections/km^2) turned out to be significant in explaining non-controllable cost differences. Furthermore, the regulator managed to establish a functional relationship between connection density (number of connections/km^2) and network density (line length/km^2) for sub-areas of the areas served by the network operators.

$$\frac{LL_j}{A_j} = \sqrt{\frac{N_{NA,j}}{A_j}} \qquad \textbf{Eq. 3} \qquad \Rightarrow \quad LL_j = \sqrt{N_{NA,j} \cdot A_j} \qquad \textbf{Eq. 4}$$

where

LL_j = line length in subarea j
A_j = area [km^2] of subarea j
$N_{NA,j}$ = number of connections in subarea j

This relationship is further used to calculate area-weighted connection numbers for the different voltage levels used as output in the benchmarking model.

▪ Australia [25]

In order to carry out analysis for strategic network planning and regulatory pricing, a techno-economic model for an idealized electricity distribution network has been created. The model assumes a homogeneous load area supplied by a single zone substation. Among a wide range of variables, a set of spatial (land use) information is used. This includes lot frontage, lot depth, lot area, occupancy rate, total lots, multiple occupancy, road width, and total number of consumers.

Using the model, the principal driver of costs was found to be customer density (customers/kilometre) represented in the model by lot frontage. This finding was consistent for urban, semi-urban, rural and sparse rural subdivisions. Average energy consumption measured in kVA was found to be only a marginal driver of total costs. However, average consumption did have a notable impact on average unit costs (c/kWh), reflecting the benefits of economies of scale.

▪ Germany [26, 27, 28, 29, 30, 31, 32, 33, 34, 35]

As the German electricity market was opened to competition in 1998, the network operators in negotiations with the network users developed the rules for the open markets. The pricing rules agreement by the German Association of Electric Network Operators (Verband der Netzbetreiber VDN), known as AA II plus (Associations' Agreement II plus, or Verbändevereinbarung VV II plus) classifies network operators in 'structural categories' to obtain information about network operators which can be compared in terms of structures. According to AA II plus, Appendix 3, the network operators are classified into 18 structural classes per voltage level. The differentiating factors are consumptions or population density (3 classes), underground cable penetration rate (3 classes) and an East/West division to account for the immense decrease in industrial load in the East.

This rough categorization was meant to be a starting point for structural comparisons. The structural criteria used and the classification limits were to be tested and adjusted on the basis of experience and scientific confirmation. As there was still a large spread of network fees within the structural classes, a refinement of the structural criteria was seen to be necessary. In the further development procedure to identify cost-raising structural characteristics, the VDN Expert Group ended up in employing the model network approach. VDN developed models for medium-voltage and low-voltage networks. The high and extra-high voltage networks are individually structured, and they have neither been modelled nor accounted for in the results. The model networks were discovered to describe with a good approximation homogeneous sections of real networks for the purpose of allocation of costs to the customers.

In RWTH Aachen, Institute of Power Systems and Power Economics, the cause-effect relation between structural characteristics of the supply area and the network structure and cost has been systematically studied in recent years, considering 110 kV [30, 31], medium voltage [32, 33] and low voltage [34] levels.

Wolffram's research claims that using Reference Network Analysis (RNA) relevant structural characteristics can be determined, and an objective correlation between the system charges and these parameters can be derived. This is proved by exemplary calculations for 110 kV networks. In the investigations, the system charges are replaced by the direct asset costs (referred to as network costs). The network costs are divided into two groups, non-influenceable and incluencable, by the system operator. The non-influenceable parameters define the minimal network costs. The difference between the real network costs and the minimum required costs represents the additional costs which are based on the influenceable parameters. In order to identify the influences of relevant structural parameters on the network costs, a quantitative separation in the minimum required costs and the additional costs is necessary. This is the main purpose of the suggested method using Reference Network Analysis (RNA).

The analysis was applied to 20 representative 110 kV networks, mostly rural and partly urban, representing approximately 20% of the circuit length of German high voltage networks. Three methods (RNA, Regression analysis, DEA) were used to complement each other for evaluating the 110 kV networks. The influence of structural parameters on the network costs was quantified with a multiple regression analysis. DEA was applied to the examined twenty supply areas and the results were then compared with the corresponding results from the RNA. In this investigation, the outputs were represented by a capacitated minimum spanning tree, the number of EHV/HV stations, peak load, length of high voltage cabling, and the input by the network costs.

For the examined networks the RNA showed a theoretical potential for cost savings between 10 to 35 %. Even after an objective selection of the outputs the assessment of the DEA method showed, in comparison to the RNA, a significant overestimation of the efficiency of the different networks. Applying restricted weights the accordance between both results could be improved. The network costs could be described by structural parameters with a high quality of estimation of the multiple regression functions and a high statistical significance. As a result, the RNA approach together with the regression analysis, as a compensation to the large amount of data and computations, provided the possibility to understand and evaluate the interdepecies of network costs and structural parameters.

Research by Löppen is analogous in its objective to the work of Wolffram. It deals with cost-determining structural characteristics for medium voltage networks using a method based on a model of the network planning process. This simulated process produces synthetically generated, but near-to-practice, tasks of supply.

In the creation of synthetic networks, certain practical, experience-based rules for HV/MV and MV/LV substation sizes were applied. The load of each HV/MV substation was determined depending on the average MV load density of the supply area and the used MV line type. The load of the MV/LV stations was calculated with the required accuracy using the known LV load density distribution. In contrast to the MV load density, only the areas of the supply area covered with buildings were considered when calculating the LV load density. The number of MV customers and MV/LV stations in the supply area were modelled according to the usage of buildings and land utilization. The shares for each kind of land utilization were taken from statistics such as land registers.

Depending on the share of open space and the wide-ranging concentration of built-up areas, a differentiation between urban and rural supply areas was used. Urban supply areas were additionally differentiated by city centre, transition zone and outskirts, because of the different shares of the four kinds of land utilization.

The synthetic network creation procedure was repeated for a number of randomly generated structural characteristic parameter sets. After a sufficient number of repetitions of this process and by varying only one of the structural characteristics at a time, possible interrelationships between this characteristic and the MV network costs could be found and quantified.

For homogeneous supply areas, using load density dependent costs for underground work, the examinations showed that the area related annual MV network costs depend on the MV density of connection points and the MV load density. The interrelationships between these structural characteristics and the MV network costs were discovered to be non-linear. With a load that is equal for all substations, as in the homogeneous case, load density can be transformed to density of connection points mathematically. Results also showed that the choice of cable types and voltage boundaries affect the MV network costs.

Based on the results for homogeneous supply areas structural characteristics that have an influence on the density of connection points and load density were examined for inhomogeneous supply areas. The usage of the results obtained from homogeneous supply areas leads to a 35-40% over-estimation of the MV network costs for heterogeneous supply areas. The functional interrelationship between the connection point density and the MV network costs is similar.

The evaluation of homogeneous and heterogeneous as well as rural and urban supply areas showed that there existed non-linear and in principle equal interrelationships between the load density and the connection point density respectively, and the MV network costs. Because of the non-linearity, aggregated structural characteristics are basically not appropriate for estimation of the MV network costs with heterogeneous tasks of supply and, depending on that, for an efficiency evaluation of grid operators. In principle, the segmentation of heterogeneous supply areas into smaller quasi-homogeneous shares and the application of the interrelationships for homogeneous areas to these shares are admissible. This method requires a criterion in order to test these subareas for extensive homogeneity, particularly in terms of the connection point density. This is necessary because the MV network costs change with the degree of heterogeneity of the connection point density considerably.

Besides, the results showed that varying the LV planning criteria of network operators causes differences in the cost of MV/LV transformation and MV network. Since these planning criteria are generally valid for all LV networks of a network operator, the LV planning criteria have to be taken into account during the comparison of MV network operators.

The German Federal Network Agency (BNetzA) submitted in 2006 its final report [35] concerning the introduction of an incentive regulation regime. The beginning of the new regulatory regime is planned for the beginning of the year 2009. The proposal is to apply a hybrid-model with several benchmarking tools. The model network approach is suggested to be used as an auxiliary tool in the first regulatory period. In the later periods, including the transition period from revenue cap regulation to yardstick regulation, a reference network approach will be used as an additional analysis tool.

▪ United Kingdom [36, 37, 38, 39, 40]

The concept of reference networks was proposed in the UK for determining optimum network design policies by statistical analysis of different design strategies on numerous similar networks. The idea was not to use real networks, but to generate realistic consumer sets and networks whose characteristics are similar to those of actual cities, towns or rural areas. An adequate number of networks with different sets of parameters would allow statistically significant conclusions. These would be applicable to actual regions, because the generated set of consumers and networks are similar to real areas defined by their specific characteristics. Studies were carried out to determine the effect of different design strategies on cost. In particular, the optimum number of substations with respect to load density has been considered. The concept could also be used in quality assessment. Additionally, the concept of representative circuits was developed. The idea is to construct only a small number of representative feeders. These are then clustered to simulate the performance of a representative network. This approach can be used to assess individual companies on an absolute basis or to compare the relative performance between companies.

▪ Idealistic electricity distribution system design [41, 42, 42, 43, 44, 45]

Model networks are usually idealistic networks based on geometrical symmetry and the homogeneous distribution of load. Geometric models used to determine the required size and length of feeders and substation spacing are presented, e.g., in [41] and [42]. Linear approximation of cost functions for lines and substations is presented in, e.g., [42] and [43]. Linearization allows the arithmetic summation of loads and removes the need for iterative procedures.

A recent pair of articles [44, 45] presents a horizon planning model exploiting idealistic system design elements, and thus is applicable to the network modelling approach. A generalized circular approach is used to describe a typical horizon-year substation service area. The proposed model produces a comprehensive set of end stage design parameters such as optimal distance between substations, primary system voltage, substation capacity, and number of feeders per substation. These parameters are determined using a direct search single-period continuous non-linear constrained optimization methodology.

▪ Finland

In Finnish research, an analytical approach using model networks has not been applied to the systematic study of cost-drivers or environmental factors. Reference networks have been used to study different development strategies for distribution networks and the impacts of regulation models. These could be categorized more as case studies, and not as systematic research, of certain parameters in network design.

▪ Critical view on EEA and its applicability

Application of engineering-economic analysis as a benchmarking tool in regulation models has been criticized for several reasons. These include reliance on the subjective judgements of engineering consultants and the data-intensivity in this approach.[15] The asset values based on fictitious networks ignoring the historical evolution of the networks and load growth may not guarantee adequate income to maintain a network.[1] EEA is seen as a possible approach to perform yardstick benchmarking in the case of very few companies, if the results are interpreted with caution.[20] If EEA uses predetermined cost functions, the results may be very sensitive to the errors of the parameters used in these functions.[24, 46, 47] All in all, it seems that EEA is relatively new as a benchmarking tool, and caution is needed if it is intended to be used for absolute comparisons.

However, network models may play an important role in the further improvement of traditional benchmarking models such as DEA and SFA. Network models are based on generally acceptable engineering assumptions and are therefore ideal for finding relevant parameters and to cross-check the validity of a given model specification. The hybrid application of several techniques and combining the advantages of each can be considered the new trend in electricity network benchmarking.[16] This kind of approach is planned to be used in Austria and Germany.

Finally, use of the engineering-economic approach, as in [41, 42, 44, 45] , for relative comparisons of different design options in general level system studies seems befitting. As these methods are quite comprehensible and transparent, they complement the spectrum of modern computer-based system analysis tools.

Community structure

A recent Finnish comparative study [48] produced a synthesis of international research concerning the impact of so-called ‘major city factors’ on the expenditure and revenue of major cities. The study primarily draws on Scandinavian research literature. The international research findings show that municipal expenditure per capita is higher than the average in major cities, and highest within each country.

Higher costs in major cities are explained by three factor groups. (1) Due to the physical structure and intensity, more co-ordination in city planning, environmental protection measures (e.g. lower noise level requirements) and infrastructure services is required. (2) Following the laws of supply and demand, the factors of production (labour, land, etc.) are more expensive, leading to more expensive services and construction costs. (3) A major city has a position as a regional or national centre. A central city provides services for a larger region, not just its own inhabitants and enterprises. Special healthcare services, universities, university hospitals, leisure and entertainment businesses, cultural activities, regional and national administration, etc., are concentrated in major cities. Moreover, many of these functions are subsidized by the city. Through increased competition for free space, these functions also indirectly burden the citizens of the central city by elevating the cost level.

Despite these logical explanations, research gives contradictory findings regarding scale economies. Furthermore, inconsistent research methods seem to make the interpretation task difficult. Nevertheless, all wire-infrastructure functions (electricity supply, gas supply and water supply) show economies of scale, albeit the above-mentioned three factor groups can all be assumed to elevate the cost. For instance, network operators are involved in complicated city planning processes and they suffer the high price level as much as any other actor in major cities. Although the 'central city' aspect brings more load to the area and thus increases load density, from a distribution network operator's (DNO) customer's point of view the indirect influence is cost-raising. The conclusion is that the 'major city diseconomies of scale' are overrun by other benefits brought by high density, but nevertheless they attenuate the favourable influence of the latter.

One must notice that the cost studies are done on a per capita basis, which does not necessarily fully reflect the cost-drivers of electrical networks. In addition, the research referred to in this comparative study is mostly from the period of a vertically integrated energy industry with economies of scope, and is perhaps inapplicable to today's restructured power industry.

Regardless of the difficulties in fully explaining or modelling the phenomena, the higher cost level in major cities is apparent according to statistics. This must be considered in the structural analysis and/or the cost functions of electrical networks.

Summary of the literature review

Although numerous factors drive costs in distribution networks, in economic benchmarking methods the number of parameters is reduced as much as possible – using proxies and composite variables - to create a robust model. The choice of relevant parameters depends also on the level of dissimilarity and the number of companies. The service territories of each company usually consist of divergent sub-areas. The results are hard to interpret and may easily prove contentious.

Based on the literature review, the most powerful tools to study the cost-drivers of electrical networks are the reference network and model network approaches. To an increasing extent these approaches have been exploited, but in several cases the detailed methods are not publicly documented. An important exception is the Swedish benchmarking model NPAM, which together with the series of German studies constitutes an important reference to this work.

A coherent result of several studies confirms that the most powerful cost-driver at the distribution network level is the connection point density, which affects the asset based costs. Another factor mentioned in several papers is the customer-mix, affecting the load related costs. Oddly enough, neither of these parameters is covered in the Finnish regulation model.*

* Customer density, indirectly included in the model, may differ substantially from connection point density.

The rarity of analytical cost structure studies, anyhow in Finnish conditions, which may differ from those of other countries, and the lack of standardized evaluation methods justify an effort to model and quantify the economies of load density.

1.5 Methodology

There are two principal methods to evaluate the cost-drivers of electrical networks: statistical analysis and network models. Statistical methods, at least as far as real networks are concerned, are excluded due to the lack of representative sample data.

Based on the literature review, several classes of network model approaches can be identified.

- Network reference models, which do not make use of standardised optimisation algorithms but instead are developed and applied on a more or less case-by-case basis. These models aim to derive the optimal costs for a given existing network by considering potential savings. This approach includes the subjective assumptions of the evaluator.
- Network optimization models, creating a reference network for an existing network based on information regarding the geographical location and the size of the loads, electricity consumption, connections to other networks, etc. Using this information, algorithms are applied to determine the optimal location of transformers and routing of lines or cables, and to select the most appropriate size and type of equipment, etc. This is done using a standardised algorithm and thus does not require any subjective assumptions other than those made in the modelling procedure itself.
- Network optimization models, creating a reference network for a fictitious but realistic supply task. Otherwise as the previous method.
- Network optimization models, creating a general model network for a fictitious supply area reflecting the essential general features of real environments. This method uses the same set of data as the previous one, but the geographical models are based on symmetrical and homogeneous load dispersion.

The first two of these models create a reference for a particular existing network, and thus these could be used in absolute comparisons and as regulation tools. The two latter methods create more general references, which can be used in relative comparisons for study purposes. Furthermore, the first method takes the existing network as a reference and then compares the improved networks with that reference. The other models create the network from scratch for a given supply task.

In this case, the choice is between the last two methods, since fictitious supply tasks have to be used. As there was no readily available tool for creation of synthetic reference networks, the obvious choice was the model network approach. One of the main objectives of this work being the increased knowledge of the cost-drivers of electrical networks, the model network approach fits this purpose well. The most important requirement for the method is that the relative proportions of networks in different areas are correct enough. An absolute optimum – even if this were an achievable target - is not required.

The methodology applied in this work has features in common with several of the reviewed engineering-economic approaches (see 1.4). The basic steps of the implemented analysis method are general to all EEA-methods: (1) Description of the supply task including the relevant characteristics of the service area. (2) Network generation. (3) Monetary assessment of the generated asset structure including operational and maintenance costs.

The first step includes a general division of geographical areas into structural classes. This resembles the zonal approach in the Chilean, Spanish and German models. The zonal approach is also required because there is not enough data to create continuous cost functions such as the ones in NPAM. Thus, an essential prerequisite to succeed is to identify significant cost-drivers and to describe the functional relationship between cost-drivers and costs.

In the second step, linear approximations of cost functions for lines and substations are used together with geometrical models of symmetrical and homogeneous load dispersion to determine optimal substation spacings as in [42]. The implemented analytic model and linearized cost functions allow a direct search of optimal substation densities. The networks are developed in a bottom-up way, i.e., modelling starts from the low voltage customer connection points and then continues stepwise to the medium voltage and high voltage levels. Two consecutive voltage levels are considered in each step, assuming that the 110 kV subtransmission level has no impact on LV networks and that the 400 kV grid does not have impact on MV networks. In this way representative networks for HV/MV substation service areas, including the feeding 110 kV networks, are created.

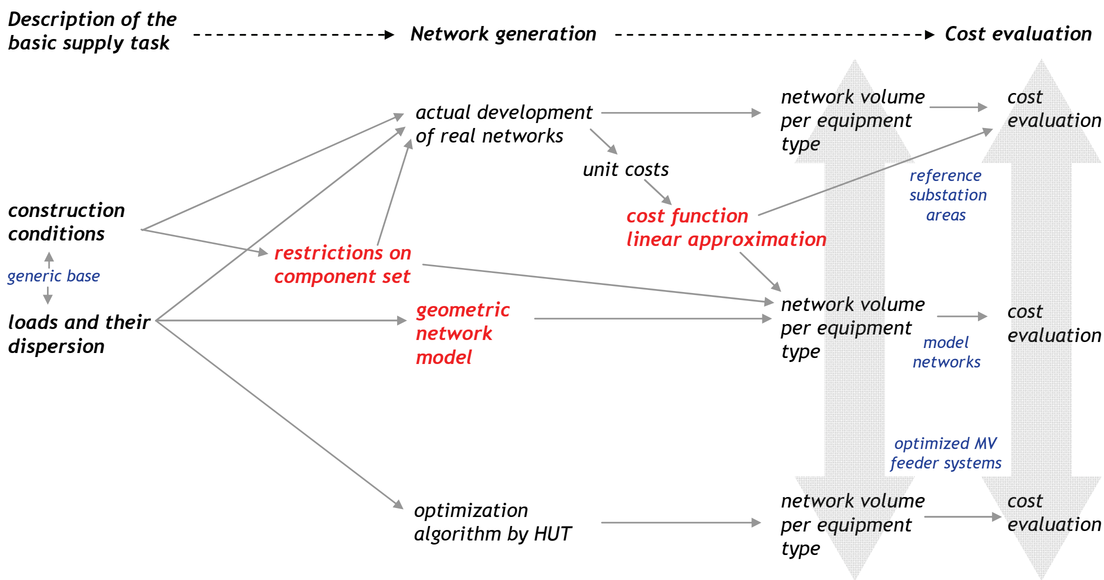


***Figure 2**. The basic elements of the applied analysis and evaluation method. The essential subtasks for modelling are shown in colour.*

Only the costs directly linked to the network assets are considered, including operational and maintenance costs, and technical losses. Annual cost is calculated using defined depreciation times. Customer related costs like metering, billing, automatic and remote meter management are not included in this study. The cost drivers for these exist in electricity markets and customer management requirements, rather than in the physical requirements of the primary network.

Reliability indices (SAIFI, SAIDI, CAIDI) are determined for sample medium voltage feeders from the model networks. By varying the network structure (looping), distribution automation alternatives and neutral point treatment, the balance between cost and reliability can be determined. Recent Finnish research concerning customer interruption costs is used as an evaluation basis.

A number of real substation service areas from Helsinki city and Kainuu in eastern Finland are used as a reference for the calculated results. These reference substations have been selected to reflect the range of load densities in Finland, and so that their service areas would be as homogeneous as possible to make a good reference. Additionally, based on the connection point data of these reference substation areas, another reference (medium voltage) network is created using an optimization algorithm developed at the Helsinki University of Technology (HUT), Department of Electrical Engineering. Thus, for medium voltage networks there will be three results for comparison: the general reference of the model network, the software-optimized reference network and the actual network.

1.6 Contribution of the thesis

The first group of contributions springs from the cost-driver analysis and the structural classification based on it. In particular the city environment, which so far has been a peculiarity under Finnish conditions, is systematically analyzed for the first time.

The second group of contributions relates to the methodology used, i.e., the model network approach which has not been employed in Finland so far. The implemented method combines elements of various other models, revised here with several supplements. The cost-effects of different external cost-drivers are incorporated into the so-called zonal approach and the applied linear approximations of cost functions for lines and substations. A new network model for rural areas, based on the road network density, is developed. Geometrical network models are applied in a novel step-wise manner to consecutive voltage levels, so that the whole network from low voltage connections up to EHV substations is included in the cost analysis in a compound way. Combined, these developed and improved model segments constitute a comprehensive new method, which enables the evaluation of the effect of external factors on the network cost. If considered qualified, the outcome can be used as a framework for the further development of model network and reference network tools in Finland. The method can be used, e.g., as an auxiliary tool in regulation model development, in general level distribution system studies and for educational purposes.

Finally, using the developed methodology, an evaluation is carried out. The variations in the network cost level and structure in different environments, i.e., the economies of load density, are explained and quantified by the generic network model used.

2 STRUCTURAL ANALYSIS AND CLASSIFICATION

2.1 Cost-drivers

Classification according to the external conditions has been generally used to find cost drivers and their descriptive parameters in order to be able to evaluate network operators operating in different environments. This has been done when determining the inputs and outputs for the efficiency benchmarking model (see literature review in 1.4). In this work structural classification is used as a tool for analytic research. This type of modelling requires that the areas are described as homogeneous, while in reality they are heterogeneous.

In an expert analysis [4] four main categories of cost drivers were found: (1) customer structure, (2) geographical service area, (3) construction conditions, and (4) climatic conditions. If we compare these categories to Figure 1 in Chapter 1, we find that the first two categories describe the basic supply task, whereas the other two describe the environmental conditions affecting network construction and operation. Therefore, the foundation for the classification used in this study was taken from previous work. However, while in DEA-studies the cost relevant parameters are found using the available data, i.e., the chosen parameters, here we are trying to create a generic description of cost-drivers starting from the basic supply task and the prevailing environmental conditions. One of the basic issues in classification is the segregation of factors according to the actual possibilities of the network operator to influence them, i.e., division between exogenous and endogenous factors. Some factors can be considered to be both.

Based on the analysis of the above mentioned study, a further analysis was carried out and several factors were added, leading up to the extended cause-effect chart shown in Figure 3. The outcome is a holistic view of the external factors affecting network cost. For clarity, all possible relationships between different factors are not shown.

For further analysis and modelling, the following factor groups were seen as significant:

- Load related factors (customers and connection points) with three important aspects: (1) modelling the single customer, (2) the behaviour of groups of customers, either similar or dissimilar, and (3) dispersion of both single customers and groups of customers.

- Construction conditions (1) in built-up environments and (2) in natural environments. The basic assumption is that the network is constructed using least-cost solutions. Which actual alternatives are available to the DNO depends on the external construction conditions. Decisive elements are the available routes and substation sites and the applicable equipment (structural) types. The structural classification must actually reflect the restrictions on these.

As we are studying the economies of load density, Figure 3 also shows a variety of density measures. The shown 'per km^2' densities (energy, peak demand or number of customer or connections proportional to geographical area) are generic density measures. Sometimes densities are expressed per network volume, but these are secondary measures since they are resulting from utilization of the generic density. This also means that they are to some degree endogenous. All these density measures are related but not necessarily in a straight-forward manner.

Land use control (planning) is the common factor between generic density measures and construction conditions in built-up environments. The density measure of a built-up environment is building efficiency or area efficiency, which is the ratio of the floor area and the lot area or the total geographical area. In city centres this ratio exceeds unity, which means multi-storey-buildings built densely side by side.

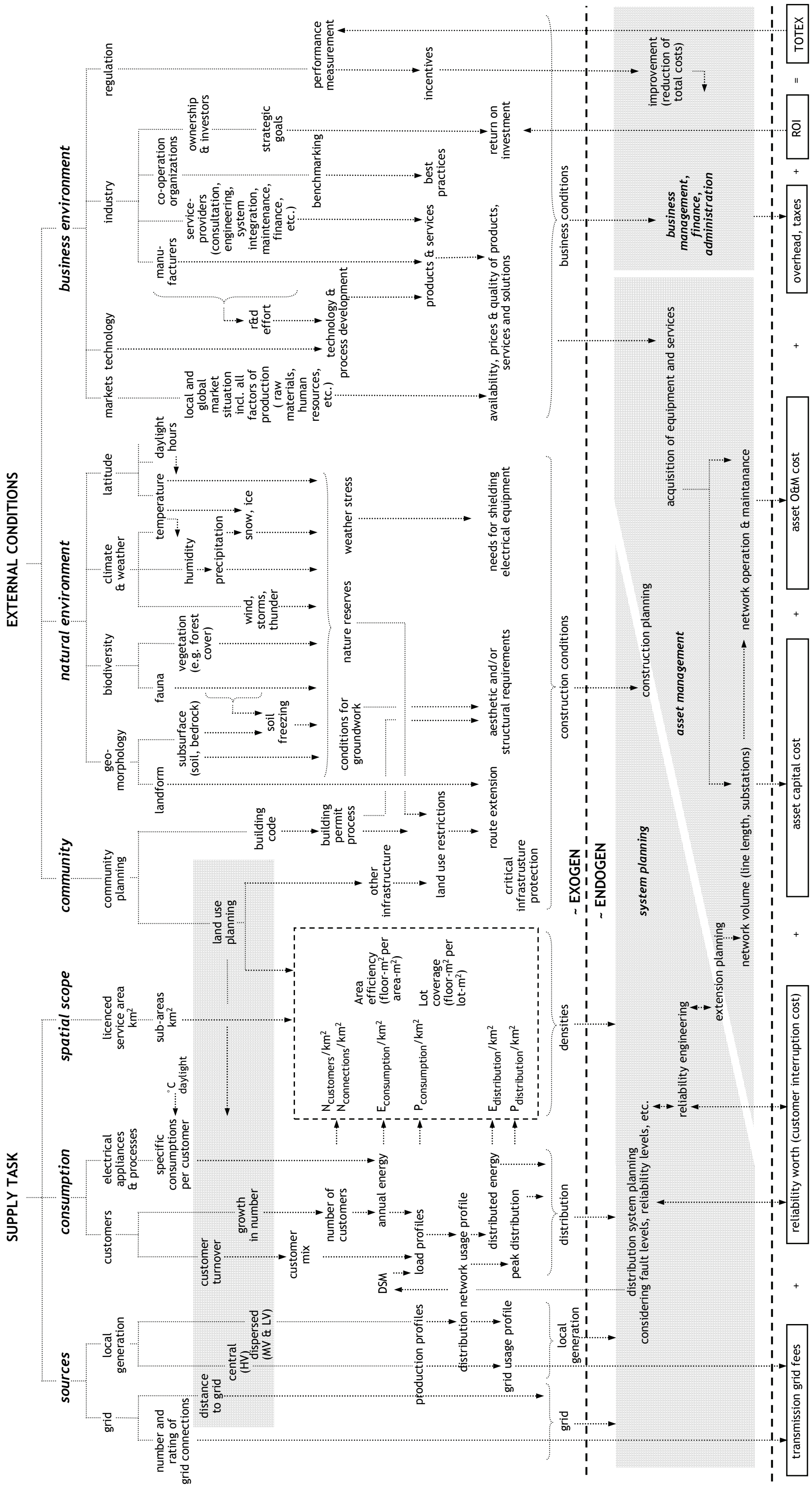


***Figure 3**. Cost-drivers and their relationships.*

A clear relationship between building efficiency *e* (floor area / total geographical area) and MV peak load density (MW / geographical area) can be detected, as shown in Figure 4. Load density seems to follow a lenient square-law (correlation factor $R^2 = 0{,}8189$), linear correlation being only slightly lower ($R^2 = 0{,}748$). The square-law effect can be explained by greater specific consumption per floor area in the areas of highest load density. There the share of high consumption commercial buildings is higher than in lower density areas.

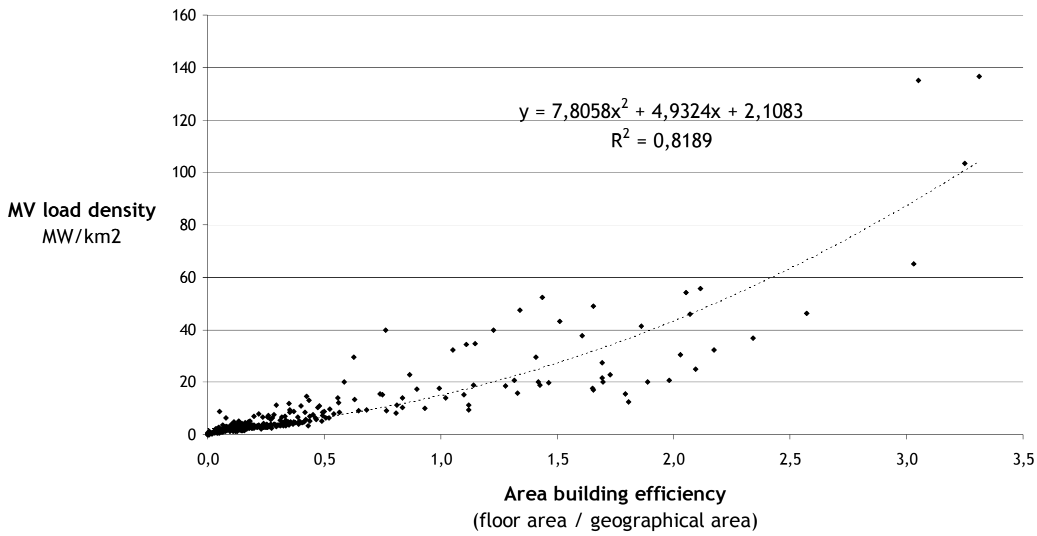


***Figure 4**. The relationship between building efficiency and MV peak load density in city subdistricts in Helsinki (data 2004).*

Building efficiency is an indicator which describes the density of a built-up area. High efficiency means restrictions for other land use, for instance in a densely built area there is no room for air insulated equipment (lines, switchgear). Hence, knowing the relationship shown in Figure 4, load density describes more or less directly not only the concentration of customers and load, but also the external construction conditions of a built-up area.

The chart in Figure 3 describes these impact mechanisms in a qualitative manner, the shaded area showing the link between land use control and customer structure. From the T&D planner's point of view, land-use planning is important for both of these aspects: the land-use plan gives the location and magnitude of the load growth and, on the other hand, the necessary T&D lines and substations need to be included in the land use plan. Communication and cooperation is needed between the land-use planners and the T&D planners. It is apparent that the planning process between these two is iterative. A land-use planner is concerned with many of the same issues as the utility, predicting needed infrastructure and services for a growing community. Land use planning is part of community planning with socio-political impacts involved. Therefore the criteria in decision-making can be quite different from the engineering-economic point of view of utility engineers.

The business environment shown on the right hand side of Figure 3 is not in the scope of this work. Well functioning markets, company management, asset management and company organization are crucial for the efficient operation of a distribution network operator, though.

The line between exogenous and endogenous factors is not always strict. The network operator may influence the load profile by demand side management (DSM) programs, take part in land use planning processes, or actively co-operate with manufacturers in the field of research and product development. What actually sets the boundary is that despite opportunities to influence, the power of decision lies elsewhere.

Not included in Figure 3 are customer management, metering, billing, etc. Electricity markets and customer management requirements are the primary cost drivers for these, instead of the physical environment.

Fundamental technical requirements, e.g., for voltage quality and electrical safety, are common for all network operators and are thus not differentiating factors.

2.2 Classification according to the basic supply task

2.2.1 Individual loads and groups of loads

The basis for the load modelling is user group classification, which segregates the users in groups where the annual energies and load profiles are similar enough. The load profiles or load curves represent the average seasonal and daily patterns and usage of energy as a function of time for a particular load class. In network information systems and customer management systems, the users have been classified into dozens of different user groups. This may well not be enough, since customer specific curves are also needed, especially for large commercial and industrial customers.

In Finland, load curves were measured in a research project conducted by the Association of Finnish Electric Utilities[49]. The results of the study are based on statistical analysis of the measured data and are accurate within a certain probability. These statistically produced load profiles have been used in this study. The annual energies per customer have been adjusted to more recent measurements. When the annual energy E_r (kWh) of a certain user group r is known, the expected value for the hourly power demand P_h (kW) for a specific hour can be determined using load profile indices:

$$P_h = \frac{E_r}{8736h} \cdot \frac{Q_h}{100} \cdot \frac{q_h}{100} \qquad \textbf{\textit{Eq. 5}}$$

where

Q_h = the bi-weekly index of the user group r
q_h = the hourly index of the user group r

The participation factors α can be determined using these typical load curves and the user group shares.

The detailed division of customers is needed in network studies and customer load forecasts in order to sufficiently accurately determine individual loads and allocate them to individual lines. In more general studies a coarser division of customers into 'composite groups' is generally used. The following composite user groups have been applied:

- households, single-family house (SFH), load profile[49] SLYIND95-601
- households, single-family house, electrical heating (SFHEH), SLYIND95-14
- households, two-family house (TFH), SLYIND95-601
- households, two-family house, electrical heating (TFHEH), SLYIND95-14
- households, row-house (RH), SLYIND95-611

- households, row-house, electrical heating (RHEH), SLYIND95-14
- households, apartment block (AH), SLYIND95-1020
- agriculture and household, composite (AGRI), SLYIND95-712
- public and commercial services, composite (SERVC), SLYIND95-6
- industrial, composite (INDC), SLYIND95-3

The required number of household user groups is relatively high because the amount of load depends significantly on the heating system. Also, the number of customers per network connection is depending on the house type.

To dimension the network, the expected peak demand in different equipment levels must be considered. The loads have to be summed to the next higher level of network (LV line – MV/LV station - MV line - HV/MV substation). The great number of customers and the mixture of several user groups mean that the peak demands of individual loads do not coincide. This means that at the higher network levels the peak demand is reduced compared to the sum of the individual peak values. To describe the non-coincidence of loads belonging to the same user group, we need the coincidence factor for each group. Participation coefficients on the other hand determine the share of the group's peak contributing to the actual peak in a particular area or equipment.

In the load curve measurement project the co-incidence factors were also determined. Unfortunately, they only apply to groups of relatively small number of customers. For this reason, we use here an applied Velander equation[50] to determine the expected demand in any point of the network:

$$P_p = W_{tot} \cdot \sum_{r=1}^{n} \left[\alpha_r \cdot k_{1r} \cdot w_r \right] + \sqrt{W_{tot}} \cdot \sum_{r=1}^{n} \left[\alpha_r \cdot k_{2r} \cdot \sqrt{w_r} \right] \qquad \textbf{\textit{Eq. 6}}$$

$$W_{tot} = \sum_{r=1}^{n} w_r \cdot W_{tot} \qquad , \textit{where} \sum_{r=1}^{n} w_r = 1 \qquad \textbf{\textit{Eq. 7}}$$

where

P_p = peak hourly demand of the observed area
W_{tot} = sum of annual energies of all user groups
w_r = per unit share of user group r of the total annual energy
n = number of user groups
α_r = participation factor of user group r (with a particular customer mix)
k_{1r} = Velander constant k_1 of the user group r
k_{2r} = Velander constant k_2 of the user group r

The distribution of user group shares follows a certain pattern, and we can define the per unit shares of each user group for the type areas. If we know the total annual energy of an area, we can calculate the average number of customers in each user group and determine the participation factors. In Figure 5 the subdistricts of Helsinki are grouped into urban core, urban, suburban and industrial areas. These geographically connected groups of subdistricts show uniform customer structures. This reflects the division of urban areas into more or less homogeneous zones.

Typical zones with uniform customer group shares and their special features are:

- urban core - dominated by commercial and public services and a small share of household load (apartment blocks); medium voltage customers are the majority (measured by the annual energy)

- urban (mixed) – dominated by commercial and public services and an increased share of household load (apartment blocks) compared to urban core; a large share of medium voltage customers, but low voltage customers are the majority
- suburban with apartment blocks – mixture of household loads (apartment blocks and row-houses) and commercial and public service loads
- suburban with mixed houses – all types of houses, share of small houses less than a half
- suburban with small houses – share of small houses more than a half, very few apartment buildings

Additionally, there are distinct subarea types, which appear as separate non-connected small (compared to substation service areas) areas:

- suburban centres – mini-size urban cores, separate small areas
- industrial – diverse and separate small areas with commercial and industrial loads

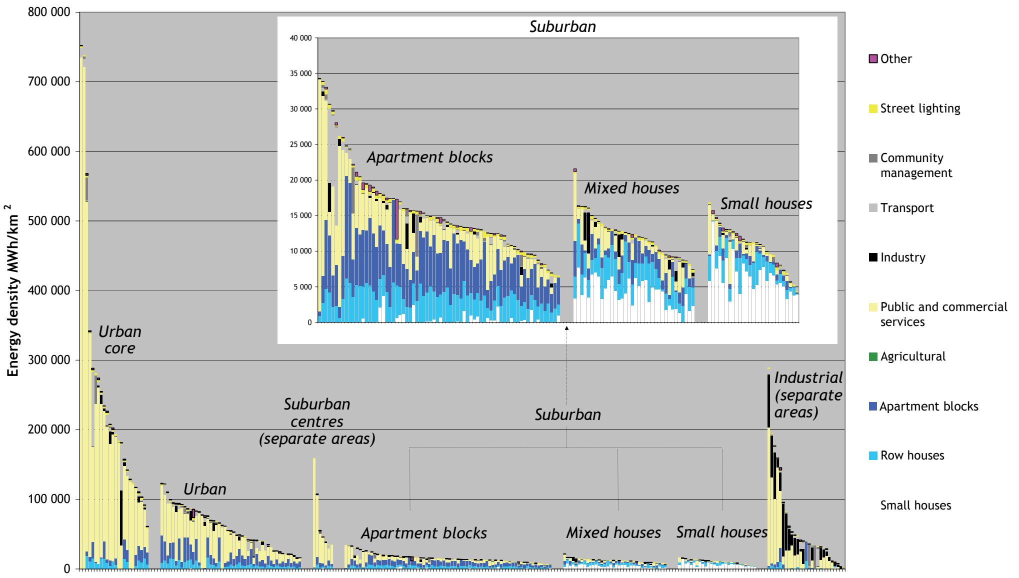


***Figure 5**. Connected city subdistricts in Helsinki show convergent customer mixes.*

Numerical indicators for these typical urban and suburban areas are presented in Appendix 1.

In rural areas the customer structure is dominated by a varying mix of household and agriculture loads with a small share of commercial and public service loads among them. Most of the services are concentrated in the urban areas.

In principle, the impact of distributed generation (DG), represented by the generation factor, has to be considered. Customers generating their own electricity and privately owned power stations supplying customers directly can have a significant impact on the maximum system demand. Unlike for consuming customers, there are no typical generation profiles. As the share of DG is minimal at present, it is not included in the analysis. Restructuring of the energy sector has caused central generation to become an almost fully exogenous factor.

Electricity use is weather dependent (temperature, wind, humidity), especially in regions where space cooling or space heating make up a large part of the total use. Network components are rated according to peak demand. A proper weather correction is needed to account for factors that have an impact on the peaks. Temperature correction could be included in load curve modelling. The lowest daily average temperatures may differ by 10…15 °C between southern and northern Finland. On the other hand, in the northern part of the country hybrid heating systems are more common. In addition, the impact of temperature is more evident on utilization time than on the peak demand. The average temperature differences in the geographical regions have not been taken into account in this study.

2.2.2 Load dispersion

Geographical dispersion of customers, according to many studies, is one of the most distinctive cost-drivers in electrical networks. Nearly all comparative methods use the length of the network - especially in relation to the number of connections or customers - to describe the environment. The nature of this factor is obvious: the further away the customer, the longer the infeeding line. This is reflected in the amount of investments per customer, and through the amount of asset to operational costs. Additionally, these long, usually overhead lines are vulnerable to natural environment, and act as fault antennas, collecting more faults per customer the longer they are. As a consequence, highest cost and worst quality of supply is expected at the same time.

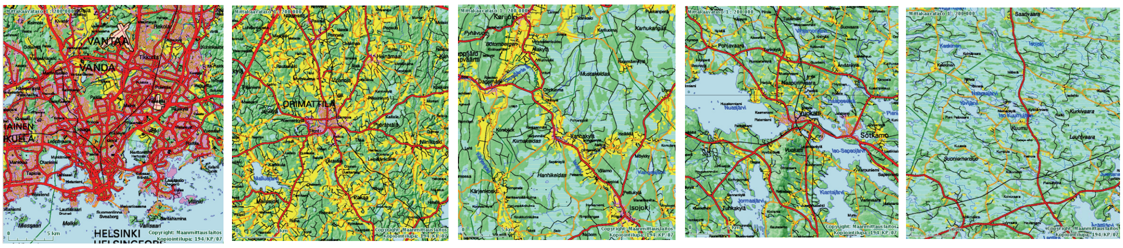
One basis for an analytical classification is the characterization of regions by Willis[51]. Table 2 describes the efficiency of land use and population density in different regions ranging from unpopulated areas to the most populated city cores. In a static sense, population density is the most distinguishing feature, which also reflects the customer and connection point densities. The local economy and other development related factors are important when the dynamics of these regions are considered.

Table 2*. Characterization of regions by Willis[51] with some Finnish examples.*

	Population	Transportation	Local economy	Examples
Unpopulated	Totally unpopulated on a permanent basis	None	No "local economy"	Parts of Lapland
Sparse	Unpopulated except for isolated outposts or villages. Islands of load within a vast ocean of unpopulated land.	Few improved roads	Natural resource extraction, fishing, scientific R&D	Northern Finland
Agrarian	Land is almost entirely used for agriculture. Isolated towns and villages and an occasional small city.	Typically about half a kilometer of improved road per km^2	Agrarian	Ostrobothnia
Rural	Land is settled for residential, commercial, and limited agriculture	About two kilometers of paved road per km^2, perhaps twice as many improved roads per square kilometer	Some agrarian, mostly regional centre area driven	Rural areas around the regional centre towns in Southern and Central Finland
Suburban	Land is "fully developed", much of it purpose-planned in large tracts	Omnipresent paved road network	Driven by regional centre economy	Small towns and the outskirts of larger towns and cities
Urban	Dense development with a majority of multi-story structures	Omnipresent paved road network, mass transit	Regional metropolitan economy	Centres of medium sized towns, transition zone between suburban and downtown in metropolitan area
Urban core	Very dense high-rise development, growth is three dimensional, mixed consumer classes	Omnipresent paved road network, mass transit	Regional metropolitan economy	Core of Helsinki metropolitan area

Load dispersion measured by connection point density covers all areas equally. The customer density on the other hand may be misleading when we are measuring the required network volume. This is due to the fact that each apartment in an apartment building is a separately metered customer of the DNO, but they share a common connection to the network. Therefore the number of customers and the number of connections may differ considerably, especially in urban areas with high-rise buildings and row-houses.

Distances between LV connection points are in urban areas in the range of 50…120 meters and the connection point density is in the range of 70…400 connections per km^2. In rural areas without any land use plans, the minimum lot size is 0,5 hectares, i.e., 0,005 km^2, thus the maximum theoretical connection point density is 200 connections per km^2 and the minimum mean distance between connections is 70 meters. In practice, due to roads and empty lots, connection point density is lower. If the distance between LV connection points is more than about 1,4 km, each connection requires its own transformer. In the highest density urban areas the share of medium voltage customers is significant, which must be taken into account in comparisons.



a) *b)* *c)* *d)* *e)*

Figure 6*. Diverse Finnish settlements, from left to right: (a) Helsinki, (b) Orimattila, (c) Karijoki, (d) Sotkamo, (e) Kuhmo. All five maps with the same scale. (Courtesy 51/MML/08 Maanmittauslaitos)*

In urban areas with zoning, loads are organized in zones with more or less similar loads (see previous Section). These loads are quite evenly distributed due to zoning and even-sized lots. In rural areas loads are seemingly randomly distributed. Actually, they are concentrated in proximity to roads. In the Finnish rural areas, different regions have their own characteristic settlement features. Population density is highest in the southern and south-western part and the settlements between towns are quite dense (Figure 6, b). In the Ostrobothnian coastal area the settlements are ribbonlike along the rivers. There, the population between built-up areas is relatively sparse (Figure 6, c). In the Finnish lake area the settlements are more dispersed compared to those of Ostrobothnia. Settlements are situated around the largest urban areas (Figure 6, d). Easternmost Finland and Lapland have the least urban areas and the rural areas are sparsely populated (Figure 6, e).

A significant proxy for customer density is the road network and road density. Practically all human activity, at least when it concerns the consumption of electrical energy, is situated along the roadside. In Figure 7 there is an example of load distribution stretched out along the roads, while the share of loadless space is significant. The figure shows an area around a 110/20 kV substation in easternmost Finland.

As a conclusion, one possibility is to base the load dispersion modelling on the road network, its density and road levels. Along the roadside the load is more or less concentrated in little villages and groups of houses. Load growth is most likely around these areas (urban sprawl, proximity effect[51]). Looking at the Finnish roadmap, from any village or town there are 3…5 main road directions plus transverse connecting roads within a certain distance from the central area. This would suggest modelling load concentration using sectors in the radial direction and zones in the transverse direction. The areas between these sectors and zones are open space (loadless areas).

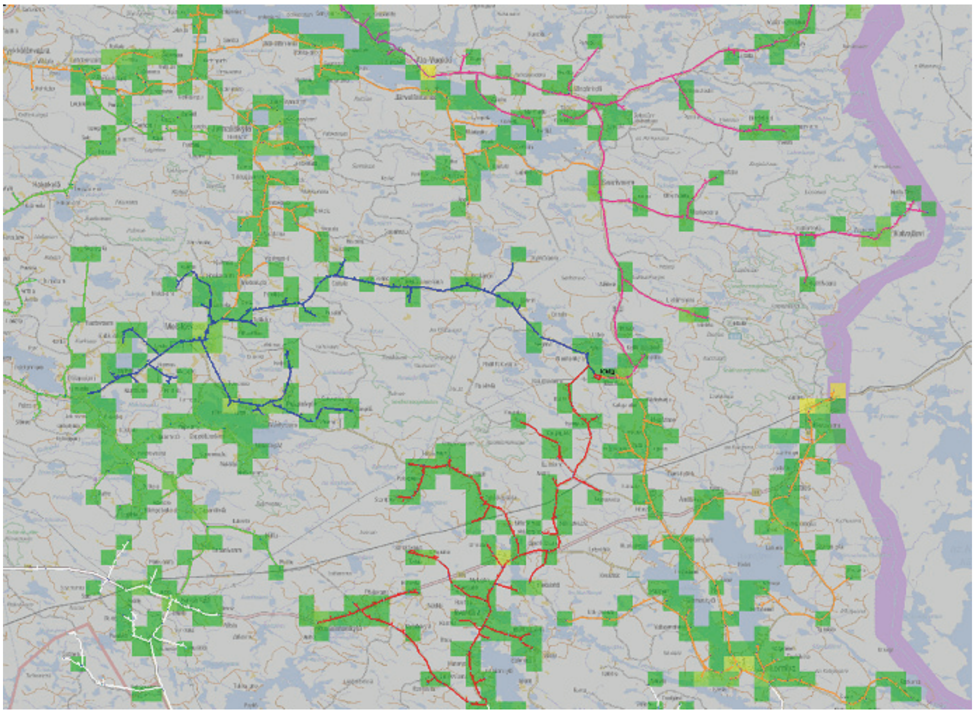


Figure 7*. An example of load distribution in a rural area in Eastern Finland, 1 km x 1 km squares with load are shown in green colour. (Courtesy Kainuun Sähköverkko Oy)*

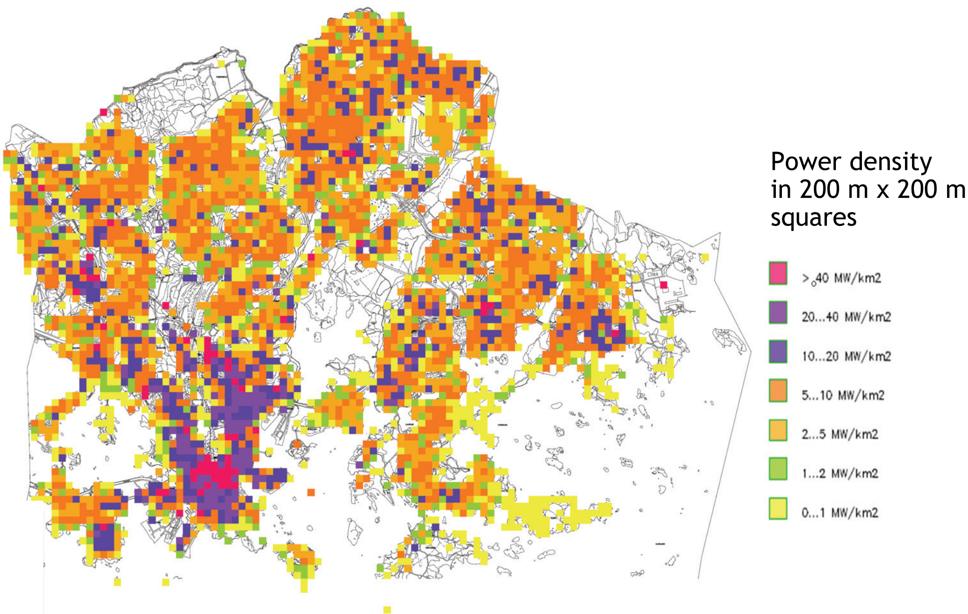


Figure 8*. Load density distribution in Helsinki city (data 2007 Helen Electricity Network Ltd).*

Figure 8 shows the load distribution and densities of a large city (Helsinki). Loadless areas are few, covering only the larger parks and sea areas. The city core is well visible, as well as the local centres and industrial areas in the middle of suburban areas. In Figure 9 a cross section of the same area shows a clear difference between the load densities of the city core and local centres and the surrounding areas.

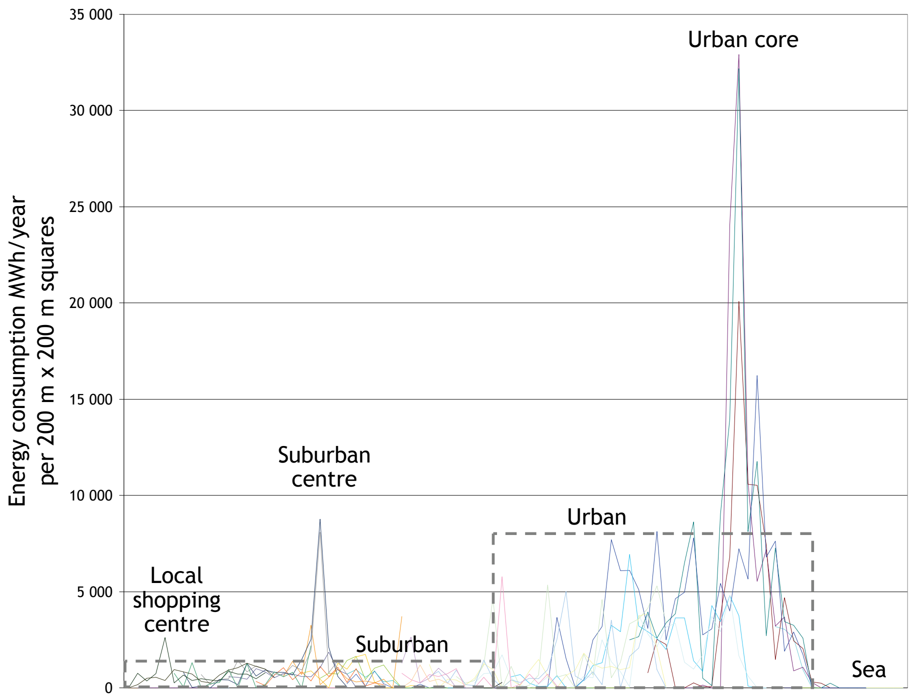


***Figure 9**. A North-North-East (NNE) – South-South-West (SSW) cross section of Figure 8 (data 2007 Helen Electricity Network Ltd).*

In urban cores the dominant loads are commercial buildings and public services, but also the share of domestic consumption is notable (see also Appendix 1). Suburban areas on the other hand are dominated by household load and related functions (schools, health care centres, markets, etc.). Between suburbs and the city core there is a transition zone with mixed loads, including offices, households, commercial load, small industry, households.

Large point loads – industrial plants such as paper mills or mines – always have to be considered separately. 110 kV customers are not considered in this study. At the medium voltage level, the share of MV customers should be considered in the model.

The modelling depends on the extent of the homogeneously coherent areas. Each voltage level has its nominal operational range. The external conditions have a different impact for different voltage levels, and thus the modelling of the environment has to be done by voltage level. The economical range of 110 kV networks is roughly 100 km, for medium voltage networks 15 km and 0,4 kV networks 0,6 km.[52] The service areas of MV/LV stations are usually quite homogeneous, but the ranges of high voltage systems are so vast that the equipment service areas can be very heterogeneous.

2.3 Classification according to construction conditions

2.3.1 Choice of equipment

Normally the choice of equipment is considered as a degree of freedom in a planning task, where the optimization includes mitigation of the effects of climate etc. Within the most densely loaded areas restrictions in land use or simply lack of space lead to ‘forced’ choices of equipment type and thus usually also to higher cost. The selection of a construction option may not be based on any technical-economical optimization, but it could be a socio-political decision. A good example of these choices can be seen in comparison of the American and the European cities. In North

America the distribution networks in suburban areas are built using overhead lines, while in Europe they are ordinarily built underground.

The type of electrical equipment structure has several significant impacts: (1) space requirement and impact on land use, (2) aesthetic impact, (3) vulnerability to external factors, (4) nature of equipment fault, (5) impact on thermal capability, (6) impact on capacitance due to dimensions of the equipment, and (7) as a consequence of the previous impacts: cost.

The general categories of structural types are:

- air insulated and open air structures (AIS, AIL, pole mounted transformers)
- closed structures with gas, liquid or solid insulation (metal-enclosed switchgear either outdoors or indoors, transformers, cables with various ways of installation)
- intermediate forms (air insulated equipment indoors, aerial cables, transformers indoors)

Due to its relatively low dielectric strength, air insulation requires larger insulation distances compared to other insulation media. To reduce the amount of needed space, either enclosed pressurized gas (usually SF_6) insulation, liquid or solid insulation is used. Sometimes an enclosure is used to be able to increase the air pressure, and thus distances may be reduced because impurities can be ignored. An enclosure and/or an indoor installation of the electrical equipment has a two-fold impact. The enclosure forms a protection against the environment, and the environment is protected – also visually – against the impacts of the equipment. As an intermediate structural form, open air structures are sometimes enhanced visually, e.g., landscaped towers for power lines.

Pole-mounted distribution transformers are used in rural overhead installations, while the urban areas are supplied by MV/LV substations in enclosures made of brick, steel or concrete, or are placed in the basements of multi-storey buildings. Cable-connected transformer stations require switchgear on both the MV and LV side. These are factory-made metal enclosed switchboards or ring-main units. All MV switchgear at HV/MV stations is metal-enclosed and placed indoors. The enclosure or the need for protective walls around transformers depends on the number of transformers, the space available and the surroundings of the substations. Open air HV switchgear is used from rural to suburban environments. Enclosed HV switchgear has to be used in suburban and urban areas. The housing type or the exterior wall coating depends on local building regulations. Underground substations are not uncommon in urban core areas.

In LV overhead line installations twisted aerial cables are dominant today both in rural and suburban small house areas, although in suburban areas new installations are normally underground. In rural areas overhead MV lines with bare conductors are in general the norm. Covered conductors have also been used but their share of the total line length is quite low. Aerial twisted MV cables have been developed but usually they are unfeasible due to the heavy structure. In Finland, wooden poles are the standard design due to the good availability of wood material. Wooden poles are also used at the HV level wherever possible. In areas with restricted space self-supporting steel towers must be used. The use of landscape towers has become more common in urban areas and at aesthetically sensitive sites.

Cables are used either because overhead lines are prohibited or for increasing reliability. The excavation and trenching cost very much depend upon the site. In city areas cables are under pavements and concrete covers, and there are other pipes and wires that make it more difficult to lay cables. Temporary traffic arrangements are needed during the construction work. Therefore not only the structural type but also the laying environment has significant impact on the unit costs of cable lines. Figure 10 presents the unit cost of LV and MV cables in the subdistricts of Helsinki city as a function of the corresponding area building efficiency. As can be seen, the range of unit cost is quite large, with a trend to higher cost in the area of higher efficiency. Similar cost curves have been produced also elsewhere[22, 32]. As a result, the percentage of underground cables itself is not a good proxy for cost level.

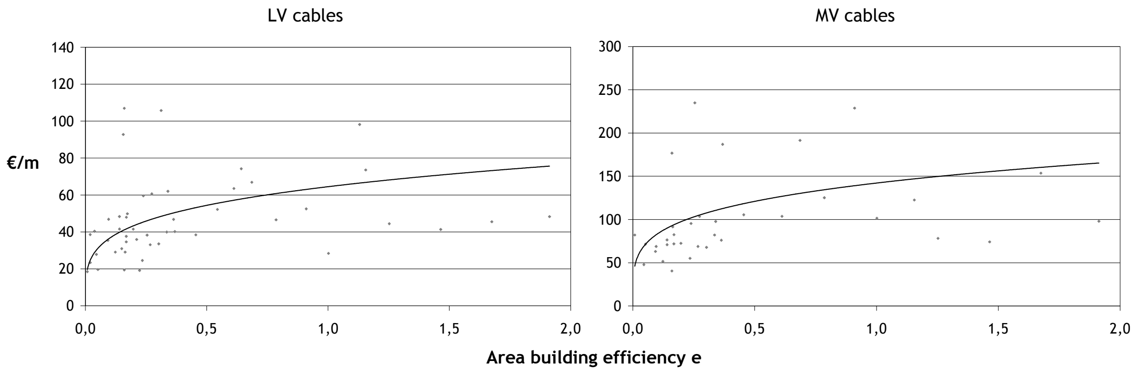


***Figure 10**. LV and MV cable unit costs in different urban environments, measured by the area building efficiency (data Helen Electricity Network Ltd 2004-2006).*

In areas of difficult terrain, e.g., mountainous or involving large river crossings, there is a bigger cost advantage with overhead lines compared to cables.[53]

The nature of a fault in the case of a breakdown depends on the insulation type. Gases are self-restoring insulators and usually serve as perfect insulation also after a breakdown. A discharge through a solid insulator causes a sustained current-leading channel and leads to a sustained fault. In liquid insulations a breakthrough discharge produces a large amount of chemical compounds and gas bubbles which lowers the breakdown voltage of the insulation. From the system planning point of view, the nature of faults is different in the case of enclosed equipment: fault probability and frequency are lower, but the repair time is longer.

The structural type has an impact on the thermal capability of the equipment: using cables it is much more difficult to reach the same capacity as with using overhead lines. This may lead to an increased number of parallel circuits and even to a different network configuration. Closed structures sometimes require forced cooling, which adds cost and leads to a more complicated system that is more vulnerable to secondary faults. Not only the investment costs and cooling losses are higher, but maintenance cost is also higher due to the complexity.

Compact structures lead to higher capacitances and thus higher charging and earth-fault currents. This may result in an increased need for compensating equipment for both reactive power and earth-fault currents. The rating of the neutral points may have to be increased.

As a consequence of all the above mentioned facts the unit costs of compact structures are significantly higher than those of standard air insulated structures.

2.3.2 Built-up environments

Structural environment is two-fold: on one side there is the natural environment, and on the other the environments with human impact. The built-up urban areas in cities almost entirely lack natural features; in the city cores not even the soil is natural.

In a built-up environment there are plenty of restrictive factors, and the network infrastructure competes for free space with other infrastructure. The amount of restrictions increases as area building efficiency increases. Additionally, in the vicinity of the network structures there are numerous neighbours and the structures are constantly visible to them (unless hidden indoors or underground). The physical transmission and distribution network is an integral part of the environment. Thus there are impacts in both directions: the network has an impact on the environment and the environment has impacts on the network. As already mentioned in Chapter 1, economically (at least at the distribution network level) the cost of the electrical network has no impact on the community structure. The distribution network covers the whole geographical area of human activities, and thus at the distribution level the construction choices have ‘global’ impact. Concerning high voltage power transmission, the impacts are not that widespread, but instead are restricted to the vicinity of the HV structures. Also, the costs of HV lines and stations may be high enough (several tens of millions of euros) to have an impact on other infrastructure projects.

A distinctive feature of urban areas is that the whole area is covered by detailed land use plans. The purpose of land-use planning is to regulate the usage of land. In a master plan, the community structure, functionally as well as physically, will be outlined. The master plan includes the overall scheme for zoning covering the whole area. The detailed plan level creates the preconditions for construction. The plan regulates for what purpose a certain piece of land can be used and how much can be built on it. The regulations also consider the height of buildings, the width of streets and other matters that will affect the structure and the townscape of the area. In the master plan and the detailed plan levels the area is divided into zones according to the land use category. Through zoning, a commune regulates building size, population density, share of open space and the way land is used. The size of a substation service area can be so large that the relevant land use plan level is the provincial or master plan. The detailed plan level is more relevant for MV/LV transformer stations and LV lines and customer connections.

Floor area, open space or lot coverage, and density controls are mechanisms that prevent an area from being overdeveloped and overcrowded. Energy usage is proportional to the floor area and interior space and therefore the electrical load can be estimated using these controls. The maximum size (or bulk) of a building on a lot is determined by the floor area ratio (FAR) assigned in the zoning regulations to each zoning district. This is the principal bulk regulation controlling the physical volume of buildings. The floor area ratio expresses the relationship between the amount of usable floor area permitted in a building and the area of the lot on which the building stands. The highest basic FAR in Finnish cities is around 3 in the highest density office or commercial districts. In American metropolitan areas FAR can be as high as 15.

Within a planning area there is a mix of detailed zones. The master plans determine larger zones with a certain mix of detailed zones. There are several basic zoning districts, e.g., residential one- and two-family residences, residential multi-family residences, commercial, mixed residential and commercial, industrial etc. These land-use zones correlate with the customer classes. This means that land use zoning explains both customer structure and construction conditions.

The area building efficiency restricts other use of land and in densely built areas the use of (air insulated) open structures is not feasible. The architectural objectives in urban environments set aesthetic requirements for all structures, buildings as well as network structures. In these areas are located many critical functions of society, which are dependent on continuity of supply. These functions have to be protected against a wide range of threats, which naturally causes additional costs.

Based on the above analysis and the results of the analysis of the Helsinki subdistricts (in 2.2), the modelling of urban areas can be based on the zonal approach. The allowed equipment types and their average unit costs can be determined for each zone according to the respective land use zone. A continuous model would require continuous cost functions for the different components (like NPAM). Given the lack of such continuous functions for the majority of equipment, the zonal approach seems to be more feasible. Restrictions for equipment types are not necessarily based on economic-engineering criteria, but may instead be based on socio-political decisions. Once again, other criteria than those related to electrical networks and their costs are usually decisive. Therefore, there is no absolute solution and different sets of restrictions could be created to reflect the different decisions. The zonal approach is suited for this kind of treatment. The set of restrictions used in this study is presented in Table 3.

Table 3. Restrictions for equipment types (special str.=special structure, prohib.=prohibited).

	Rural	Suburban	Urban	City core
- HV overhead lines	Allowed	Allowed	**Special str./Prohib.**	**Prohibited**
- HV cables in surface soil	Allowed	Allowed	Allowed	**Special str./Prohib.**
- HV cables in tunnels	Allowed	Allowed	Allowed	Allowed
- HV/MV substation AIS	Allowed	**Special str./Prohib.**	**Prohibited**	**Prohibited**
- HV/MV substation GIS in a building	Allowed	Allowed	Allowed	**Special str./Prohib.**
- HV/MV substation GIS underground	Allowed	Allowed	Allowed	Allowed
- Distribution lines, overhead lines	Allowed	Allowed	**Prohibited**	**Prohibited**
- Distribution lines, aerial cables	Allowed	Allowed	**Prohibited**	**Prohibited**
- Distribution lines, cables	Allowed	Allowed	Allowed	**Special str./Prohib.**
- Distribution lines, cables in ducts	Allowed	Allowed	Allowed	Allowed
- MV/LV stations, pole mounted	Allowed	**Prohibited**	**Prohibited**	**Prohibited**
- MV/LV stations, separate house	Allowed	Allowed	**Special str./Prohib.**	**Prohibited**
- MV/LV stations, in buildings	Allowed	Allowed	Allowed	Allowed

It must be noted that ‘allowed’ does not mean that it is economically reasonable to use any type of component. Therefore, the restrictions are only significant when it is assumed that the least-cost solution is always used. ‘Special structure’ means that a certain type of equipment cannot be used as such, but some additional structural and/or aesthetic solution is required. For example, landscape towers in certain areas or a substation integrated in a high-rise building always require customization. These custom structures are always cost-raising, but the cost is usually lower than in the possible alternative. Because the cost falls somewhere between the basic solutions, it is not necessary to model these special structures.

2.3.3 Natural environment

In rural environments, overhead structures tend to dominate and so the description of these environments has to include vegetation and climatic conditions and combinations of these. Soil characteristics are relevant, particularly in the case of underground cables.

Concerning vegetation, forest cover has impacts both on the building and operation of t&d lines. In addition to cutting down trees, a compensation to the land owner based on the price of timber has to be paid. The highest compensations are around 10 k€ per hectare, as the mean value is around 2 k€. As one hectare is 100 x 100 meters and the space needed for a line is 10 meters wide, a payment sum corresponding to one hectare is required to build one kilometre of line. If the line is situated along the road-side, the line only takes half the amount of forest. Low accessibility increases both investment and maintenance costs. Correlation between the dispersion of loads and forest cover is obvious, as in the rural area it is likely that the lines run through forests. The lines in forests have more impact on the unit cost and reliability than on the choice of component types.[4,7]

The impact of wind is channelled through forest cover. In windy areas mechanically more strong structures are required. The investment cost of distribution lines can be 10…20 % higher in areas of similar forest cover but different level of windiness. [4,7]

The salient effect of thunder storms is the impact of wind. Compared to wind, the impact of lightning strokes was considered small[4,7]. Strong winds in connection with thunder storms and direct lightning strokes on trees may cause trees to fall on lines. The frequency of lightning strokes has been measured by the so-called keraunic level, which represents the empirical number of days with lightning. The keraunic level is highest around the equator and gets lower when approaching the poles. In some African, South-American and far-eastern countries the keraunic level is 150…200, while in Finland it is in the range of 5…15. The keraunic level does not separate lightning strokes between clouds and strokes between the ground and the cloud. In Finland's latitudes, 60…70 % of strokes occur within or between clouds (in the tropics: 85 %). The lightning counters show a level of 0,6…2,5 strikes per km^2 per year. At the medium-voltage network level surge arresters are assumed to be a standard solution for protection against over-voltages. At the low-voltage network level over-voltage protection is not that common, but the twisted air cables which have been systematically used in Finland for more than 30 years are more insensitive to strokes in the vicinity of lines (due to a significant difference in induced overvoltages compared to lines with bare conductors).[54,55]

Also, the impact of accumulated snow is related to forest cover. When snow has accumulated on the line side branches of a tree, the mass of sleet snow may bend the tree over the line and cause a fault and a line failure in the worst case. Snow and ice covers the structures and therefore there are higher requirements for the mechanical strength of equipment. For example, the electrically otherwise adequate cross-section may be mechanically inadequate. The poles have to be placed more densely. Snow and ice on the conductors effectively increase the area exposed to wind, and the extra weight imposes additional mechanical loading on the conductors.[53] The snow accumulated on wires has to be removed to prevent mechanical overloading. Deepness of snow cover makes it more difficult to move about which is reflected in operational costs. Investments due to snow and ice loads are higher than those due to windiness. The amount of snow was considered a significant differentiating factor in O&M cost levels. [4,7]

Very low temperature also stresses conductors and requires higher mechanical strength. In the north the temperature could be as low as -50°C. Equipment choice for these circumstances may be quite limited, which has a cost-raising effect. Soil freezing was considered not to have a significant impact on costs (of overhead structures). [4,7] Concerning cable laying and excavation, the work is seasonal and depends on the depth of soil freezing.

For different levels of air pollution there are several pollution classes for insulators. The salt content of the Baltic Sea is quite low, and therefore in Finland the most severe pollution classes are not generally required. The impact of polluting industrial plants is limited to the close vicinity of these plants and the effects are not widespread. Therefore, pollution is not a significant differentiating factor overall.

The amount of snow, temperature, etc., are all winter related. The harshness of winter therefore has an impact on costs. In addition, the winter effect is influenced by the forest cover. Winter could be an environmental indicator, and it could be measured using the average temperature or the deepness of snow, the latter being more significant.

Forest cover, windiness and thunder storms have an effect on overhead networks. The effect of wind and thunder is most considerable if the lines are in forests. The direct effects of lightning are not considered significant. The amount of lines running through forest is an indicator. Because there is no systematic analysis made of the impacts of winter conditions and forest cover, a possible way of depicting these external factors would be the use of a rough "harshness factor". The level of this factor for rural areas with overhead networks could be 1,0…1,3 (i.e. increasing the cost of MV and LV lines and pole-mounted transformers by 30% at the maximum) based on the expert judgement in [4]. It must also be noted that these factors are partly endogenous, because the reliability level of the network is within the power of the network operator. On the other hand, there are also cost-raising factors for roadside situated lines, such as numerous elbows, single-sided supporting and occasional short cable segments. The cost difference is therefore case-specific rather than general.

The service areas of rural substations are always mixtures of forest, open field and roadside environments. A similar zonal approach as used in the urban environment can not be applied. The unit costs used in this study are based on the costs of companies in recent years, reflecting the average mixture of structures. Thus the adjustment of the cost level to the prevailing conditions is at least partly already embedded in these costs but is not possible to be specified. Therefore, in the general cost structure study, only this average cost level is used. In reliability studies, however, the distinctly different performance levels of lines in forest and lines situated in open fields or along the roadside have to be considered. These performance indicators will be presented in Chapter 5.

2.3.4 Topographical restrictions on line routes

Topography determines the line lengths both in rural and urban environments. In urban areas the available routes are determined by the street network. Natural landforms and other topographical features may increase the line length. These can be water systems, mountains, nature preserves and airfields. The overall impact of altitude differences in Finland (with no high mountains) is estimated to be quite small.[4]

An analytical model of amorphous rural areas with sporadic occurrence of natural features is quite impossible. Therefore empirical adjustment factors for line lengths are used. In urban areas with fixed street grid it would be possible to create a geometrical model with a route length of $|\Delta x|+|\Delta y|$, but the urban areas can be handled using empirical adjustment factors as well. A general approximation of $\sqrt{2}$ is used as a basic assumption in urban conditions.

The adjustment factors for line lengths at different voltage levels based on an analysis of existing Finnish networks in divergent environments are shown in Appendix 2.

2.3.5 Regional cost levels

Statistical comparisons show clear differences in cost levels (the rents of premises, the prices of property and labour cost). However, the statistically evident major city surplus is already included in the cost data used and cannot be considered twice. The same applies to rural network costs. In order to model this aspect, the component unit prices should be segregated into smaller segments to take into account the impact of regional cost levels. The exceptions are the cost of land and the cost of buildings, because the statistical data can be incorporated into the model with segregated building blocks for these cost components (substation buildings and lots).

2.4 Description of the chosen structural classification

In rural areas the installation environment is dominated by ‘open space’ with a diverse natural environment. The dominance of natural environment becomes stronger along with the share of open space and the dispersion of loads. In the natural environment there are usually no restrictions on using the most cost-effective types of equipment. Therefore the total cost of a feeder system is affected by connection point density (CPD), but the unit cost of lines does not vary with CPD. Therefore, load dispersion and factors related to natural environment are describing the cost–relevant features. An analytical model of amorphous rural areas with sporadic occurrence of natural features and various cross-effects would be quite complicated and would require a large detailed database of structures and their costs. Therefore, in addition to the basic evaluation with standard prices, only the effect of a harshness factor (depicting the effects of forest cover mostly) based on expert evaluation will be discussed (see 2.3.3).

Urban areas, on the other hand, are organized through land use control into zones with distinct borders between different types of areas. In addition to the effect of CPD on total line length, the environment is affecting the unit cost related to CPD. Based on spatial analysis it is also evident that the land use zones describe all relevant features: customer mix, load dispersion and construction restrictions, the last leading to an obligation to use more expensive structures. Subdivision into three basic zones - urban core, urban and suburban – seems to be adequate, although several sub-types for suburban zones based on different customer mixes (house types) are needed. In urban zones with a requirement to use shielded equipment there is no need to model weather stresses at this level of general study.

Thus, we end up with four basic zone types (Figure 11) plus several sub-types for different customer mixes and natural features. Between these zones there are transition zones which are more difficult to model. Since connection point density is expected to be the strongest cost-driver, it is assumed to be possible to interpolate the cost level in these areas. By overlapping typical areas and their parameters including densities, a piecewise continuous approximation of costs in relation to load density can be perceived. The number of described zones is the result of a compromise between the target to fully capture the cost structure in a network area and the difficulties in finding the relevant information. Continuous unit cost functions could be extracted from a large mass of data using regression analysis and evaluation of the impact of external conditions. In the lack of these studies, the zonal approach is the only feasible one.

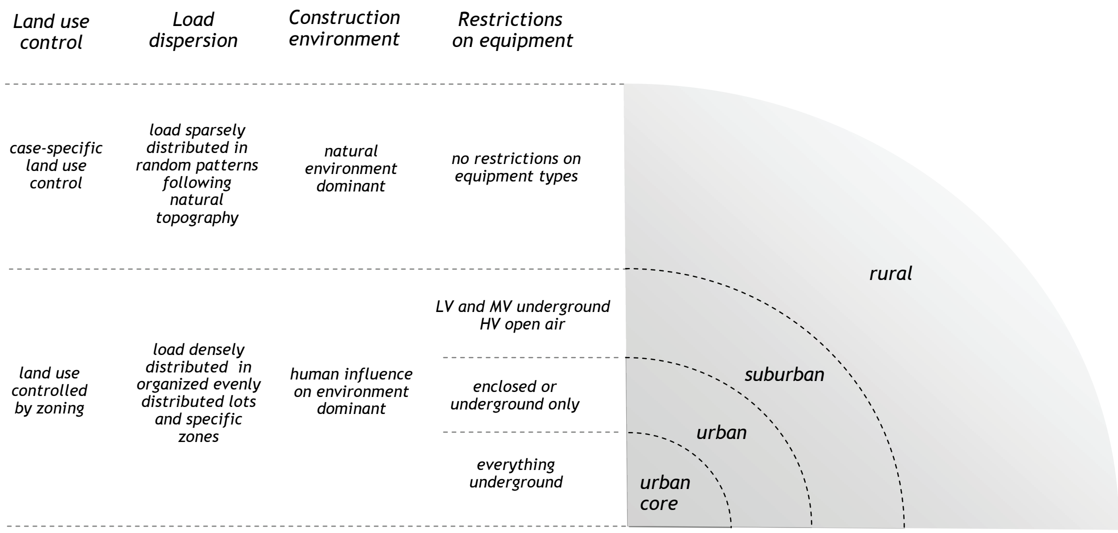


Figure 11*. The general outline of the zonal approach.*

In the interpretation of the results the size of the service territories of equipment has to be compared with the uniform and homogeneous zone sizes. The service area of an LV line or MV/LV station is geographically quite limited and their service areas are typically of one zone type only. Service areas of MV feeders and substations can cover large geographical areas and comprise several zones. In Finnish conditions the HV system always feeds divergent regions. In large cities and in rural areas the more or less homogeneous zones are large enough to cover the whole HV/MV substation service territory with a single zone type alone. In smaller cities and suburban transition zones substations may feed divergent areas. These have to be evaluated using reference networks or by interpolating the results of the zonal approach.

The parameters for each zone include customer mix, equipment choice (Table 3) and adjustment factors for line lengths. Full description tables of the zones or the typical structural classes are presented in Appendix 3.

3 COST FUNCTIONS

3.1 General

In system optimization, after having defined the planning objectives, an objective function to be minimized or maximized has to be developed. Ideally it is a life cycle cost function including not only the costs of investments but the total cost including yearly operational and maintenance costs. A comprehensive cost function could also include societal costs, e.g., customer interruption costs and environmental costs. Of these cost categories, the investment cost, O&M cost and losses are tangible costs for the network operator. Outage costs for the most part are costs to customers and they do not normally include capital transfer between the DNO and the customer. Environmental costs are partly included in investments (preventive actions), partly they are O&M costs (direct consequences of incidents), and partly societal costs (indirect effects to the environment).

The optimization task is easier if some factors can be set as constraints in the planning task. These are usually safety related issues, voltage quality, etc, or environmental constraints. These constraints indirectly affect both capital and operational costs. It is assumed that for the prices or costs used in this study, safe and environmentally acceptable equipment can be purchased and maintained. Thus, if the necessary constraints are checked, the minimum cost solution is also feasible. Another way to make the optimization task easier is to value some factors in monetary terms. This is a frequent procedure concerning the customer interruption costs (CIC), using commonly agreed unit values for CIC. It is very difficult to estimate other societal costs and evaluate their indirect impacts. There are many reasons for this, such as the complicity of cause-effect relations and the lack of data for evaluation. In the long run, the societal impacts are estimated by society itself. Finally, this leads to political decisions that impose certain constraints, for instance reliability levels or approved standards for aesthetics.

A general objective function to be minimized in system optimization can be expressed as follows:

$$C_{tot} = \sum \left(C_{inv} + C_{loss} + C_{O\&M} + C_{out} \right) \qquad \textbf{\textit{Eq. 8}}$$

where

C_{tot} = total cost
C_{inv} = investment cost
C_{loss} = cost of losses
$C_{O\&M}$ = operational and maintenance costs
C_{out} = outage costs (i.e., repair costs and customer interruption cost)

In order to constitute a system level objective function we need the cost functions of the basic building blocks of the transmission and distribution system. There are three basic types of building blocks: lines (connecting nodes), substations (nodes with transforming from one voltage level to another plus switching arrangements) and switches or switching stations (nodes without transformers). Using these cost functions and applying some form of network optimization or system simulation tool to generate an optimal or near optimal network with a defined set of these basic components, evaluation of the network cost is possible. In order to analyze the cost structure of the networks the cost division in predefined elements has to be established and maintained throughout the analysis.

An essential aspect affecting the cost is the considered time frame and timing of costs. The costs that occur at different times must be made commensurable. The yearly costs during the life of the equipment are not equal each year, but instead vary due to load growth affecting the amount of losses and energy not supplied (ENS). The cost of a major overhaul differs from the 'normal' maintenance cost level, and is significant compared to the initial investment cost, and thus must be separately considered. For these reasons, an average annual cost must be determined based on the evaluation of the total life cycle cost. When this levelized annual cost is allocated to the average yearly transmitted energy values, the accomplished 'per kWh' reference cost can easily be compared with network fees, for example.

The component cost functions have to reflect the cost-dependencies on the external conditions. According to the analysis in Chapter 2 these are the load characteristics and the construction conditions. In addition, the service life time determines the amount of aggregated yearly costs.

$$C_{component} = f(\text{life time, load characteristics, construction type}) \qquad \textbf{Eq. 9}$$

The lifetimes of equipment vary, weighted lifetimes for the whole network being between 30 and 40 years. The range of lifetimes of primary components is between 30 and 50 years, while the lifetimes of secondary equipment are far shorter. If the latter are expected to be half of the primary equipment life, then a continuous renewal period of T/2 + T/2 = T (e.g., 20+20 years) can be used. The shorter period is applied for secondary equipment. The major overhauls of primary equipment can also be scheduled at the half-lives of the primary components.

The load characteristics include the peak power in the first year, the load profile (usually expressed simply as the peak utilization time) and load growth rate and period of load growth. These factors affect component load current ratings. The short circuit withstand level usually increases with the rating and is not necessary to notify separately in this case.

A typical load growth pattern for a new substation service area is such that the initial load is 40 % of the sum of the transformer capacity. In 20 years the load increases to 90 %. (Seemingly, this fits the 20+20 years model, but in fact the load growth is not linked to the secondary system lifetimes or the major overhauls.) The load growth pattern of an individual MV line or LV connection is different; there a modest (or zero) load growth during the whole period can be assumed. At the feeder level, the growing load means the building of new lines in the course of the load growth period. Since, however, the majority of the evaluated networks are in their mature phase, i.e., at or nearly at the planned full load, another strategy is to assume a steady but modest growth during the renewal period. For example, a load growth of 0,12 % per year leads up to a total growth of 5 % in 40 years. This latter approach has been used throughout this study because it is more relevant when comparing the static (present day) fully developed networks with the calculated values.

To fit the component into the environment the mechanical and structural design has to be defined. Matching the relevant components with these external conditions is implemented through the cross-reference table in Appendix 3 (or Table 3 in the text).

3.2 Cost elements and cost data

The two basic types of expenditure are capital expenses (capex) and operational expenses (opex). Usually the investment cost is paid at once, but capital costs can also be a yearly cost if the equipment is rented or paid in instalments. Investment cost includes all material, planning, manufacturing, construction, commissioning and project management. The operational expenditure directly concerning the network assets include the costs associated with the operation, repair and maintenance, and the cost of losses. Exogenous factors have an impact both on capex and opex, and through capex to opex. Opex and capex are thus linked, this fact being utilized in the so-called network volume model used in benchmarking.[2] In addition, costs associated with repairing the network can often be mitigated by increased capital expenditure, e.g., enforced or shielded structures and network automation.[56] Network losses can be reduced by investing in redundant current paths or higher rated components. Therefore, it is necessary to consider alternative total cost compositions in system level studies.

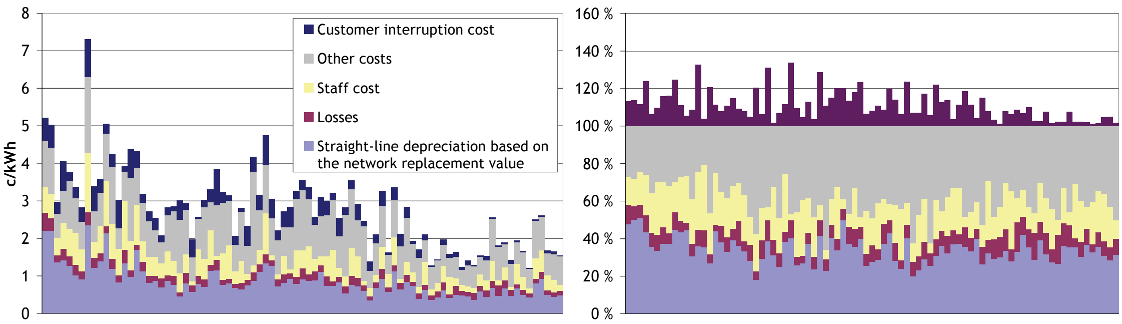


Figure 12. *The cost structures of 85 Finnish DNOs presented in order (from left to right) of increasing amount of urban network. The DNOs are sorted by (1) the amount of city area cable and (2) the MV network length per customer. Straight-line depreciation based on the network replacement value is used instead of book-keeping value. (Data 2006, gathered by the Finnish Energy Market Authority[57])*

Another way of dividing cost is to divide it into variable and fixed parts. Fixed costs are not dependent on load, for instance the maintenance cost of a certain type of transformer is the same independent of the energy or peak load. Since the no-load losses stay constant over time (dependency of voltage not taken into account), the discount factor for no-load losses is dependent only on interest rate and the operating life time. Copper losses on the other hand are load dependent and are thus variable.

Yet another way of dividing costs is to divide them into load related and non-load related expenditure. There are also load related capital costs in the form of choices of the cross sections of conductors and transformer sizes.

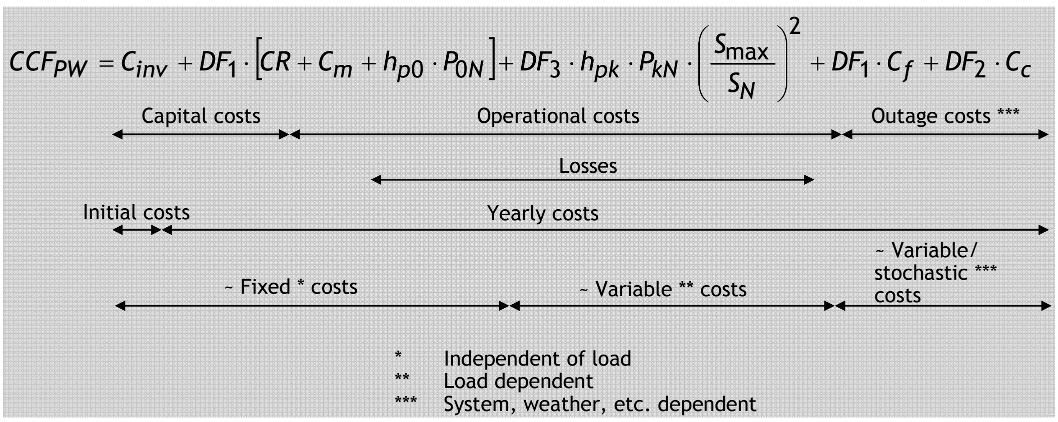


Figure 13. *Comprehensive division of network costs. CCF_{PW} = comprehensive cost function of an item of equipment, C_{inv} = investment cost, CR =network rents or instalments, C_m = yearly maintenance costs, h_{p0} = unit price of no-load losses, P_{0N} = nominal no-load losses, h_{pk} = unit price for load losses, P_{kN} = nominal load losses, S_{max} = peak apparent power in the first year, S_N = nominal apparent power rating, C_f = repair costs, C_c = customer interruption cost, DF_1= discount factor for yearly costs with constant cash flow, DF_2 =discount factor for yearly costs with linear relationship to the annual load growth, DF_3 = discount factor for yearly costs with quadrature relationship to the annual load growth.*

Figure 13 shows a comprehensive cost function and the above mentioned divisions into cost elements. The present worth is calculated using the appropriate discounting factors $DF_1 \ldots DF_3$.

▪ ***capex***

As much as possible, the unit cost list[58] of the Finnish Energy Market Authority (EMA) is used. This unit cost list is based on aggregated data from the Finnish DNOs. For HV systems the EMA-list is not very extensive or representative. In the lack of a broader data base, the company data base has to be used for HV lines, HV/MV substations and the special structures used, e.g., steel towers and concrete cable channels. For buildings and excavation work, general unit cost data is available. Similarly, the price of land is based on Finnish statistics from real estate transactions. The cost data used in this study is presented in Appendices 4 and 5.

The residual value of equipment reaching its accountancy age is usually quite small. Furthermore, there are disassembling and disposal costs at this point of service life. Therefore, the residual values of all components at the end of their service lives are assumed to be zero.

▪ ***opex***

For opex or maintenance costs there are not any aggregated databases. Applicable data from several sources has been gathered, the main source of data being the DNOs for Helsinki and Kainuu. The yearly maintenance cost of primary equipment is in the range of 0,1…0,8 % of the investment; that of the main transformers 1,0…1,5 % and of secondary equipment 1,5…2,5 % respectively. Thus the total share of maintenance costs of yearly costs is normally not more than around 10 %. Therefore it is more crucial to model accurately the capital investments in a primary system level study. In secondary system or network automation system studies the share of operational costs is higher and better accuracy more relevant.

▪ ***losses***

Prices for losses have been calculated using a market price for energy [€/kWh] and a marginal price for different voltage levels [€/kW,a]. The latter cost component is due to the fact that losses at a deeper network level have to be fed through the whole upstream supply system. Thus, LV system losses involve the highest cost per kW of loss.

▪ ***outage costs***

Outage cost is composed of customer interruption cost (CIC) and the network repair cost. The latter is typically very small compared to CIC. Also, compared to electricity prices, customer interruption costs are very high, the difference being a few decades.

Customer interruption cost is depending on the system design and is thus largely endogenous. This will be analyzed in Chapter 5.

The Finnish Energy Market Authority uses the total cost concept including the customer interruption cost (CIC) as a cost of the DNO. An evaluation base has been produced by processing the results of the latest CIC research study in Finland[59] to define Sector Customer Damage Functions (SCDF) and a Composite Customer Damage Function (CCDF) for the whole country[60, 61]. The latter is used in CIC evaluation in the Finnish regulation model. Here we use the SCDF values to emphasize the differences in the customer mixes of the typical service areas. The regional differences observed in the research are not taken into account.

3.3 Time value of money

A method based on present value is used to evaluate cash flows and measure costs that occur at different times. Because only the cost partition is covered, the term 'present worth of cost' is valid. To understand better the perceived cost level, the result is expressed in terms of a constant level of cash flow (cost), the annual worth.

Suppose a project has an associated cash flow stream

- $(C_0, C_1, \ldots, C_n)$ over n years

A present value analysis uses a fictitious ideal bank with a constant interest rate *i* to transform this stream hypothetically into an equivalent one of the form

- (PW, 0, 0, …, 0), where PW is the present value of the stream

An annual worth analysis uses the same ideal bank to hypothetically transform the sequence to one of the form

- $(0, C_a, C_a, C_a, \ldots, C_a)$

The value C_a is the annual worth (over n years) of the project. It is the levelized average annual cost generated by the project if all amounts are converted to a fixed n-year annuity starting the first year.[62]

As the average annual energy (kWh/a) is known for each evaluated case, the annual worth (€/a) can be converted into an average reference cost (c/kWh).

▪ ***discount***

Present worth analysis discounts the value of future costs and savings versus today's costs and savings. The discount rate is the perceived rate of reduction in value from year to year. The present worth factor *PWF* is related to this discount rate:

$$PWF(t) = \frac{1}{(1+i)^t} = \frac{1}{\delta^t} = \delta^{-t} \qquad \textbf{Eq. 10}$$

where

δ = $1+i$
i = interest rate (discount rate) in decimal terms and
t = future year

The annual cash flow can be assumed to be made up of components which can either be considered as constant over a number of years, increasing by a fixed percentage each year, or increasing quadratically in relation to annual load growth. If the annual cash flow is constant C_a [53]:

$$PW = C_a \cdot \left[\frac{1}{1+i} + \left(\frac{1}{1+i}\right)^2 + \ldots + \left(\frac{1}{1+i}\right)^t\right] = \frac{C_a}{i} \cdot \left[1 - \frac{1}{\delta^t}\right] = C_a \cdot DF_1 \qquad \textbf{Eq. 11}$$

where t = review period in years and

$$DF_1 = \frac{1}{i} \cdot \left[1 - \frac{1}{\delta^t}\right]$$ = discount factor for constant cash flow **Eq. 12**

When the load and costs increase by a fixed amount g each year [53]:

$$PW = C_1 \cdot \gamma \cdot \frac{\left(\gamma^t - 1\right)}{\left(\gamma - 1\right)} = C_1 \cdot DF_2$$ **Eq. 13**

where

C_1 = costs in year 1 and

$\gamma = \frac{(1+g)}{(1+i)}$ (g and i in decimal terms)

$DF_2 = \gamma \cdot \frac{\left(\gamma^t - 1\right)}{\left(\gamma - 1\right)}$ = discount factor for yearly costs with a linear relationship to the annual load growth **Eq. 14**

This equation is particularly useful when modelling the costs of outages.

For the situation where costs have a quadrature relationship to the annual load growth g, the variable γ is modified to γ_1 where

$$\gamma_1 = \frac{(1+g)^2}{(1+i)}$$

and thus

$DF_3 = \gamma_1 \cdot \frac{\left(\gamma_1^t - 1\right)}{\left(\gamma_1 - 1\right)}$ = discount factor for yearly costs with a quadrature relationship to the annual load growth **Eq. 15**

This modified version is suitable for loss calculations, particularly when considering the costs of copper losses which have a quadrature relationship with loading.[53]

▪ ***annuity***

If the initial and annual costs are divided evenly across the review period and added to the appropriate cash flows, the annual payment C_a for a single investment with present worth PW is given by:

$$C_a = PW \cdot i \cdot \left[1 - \frac{1}{\delta^T}\right]^{-1} = \frac{PW}{DF_1}$$ **Eq. 16**

where T = life time of the investment

▪ ***interest rate***

The time value of money is expressed concretely as interest rate. For present value calculations it is best to use rates that represent true interest rates, since we assume that the cash flows are certain. From the standpoint of planning, inflation makes no impact on the relative costs of the various components, so it can be ignored, making the planning easier[42]. Real interest rate is the "money interest rate" minus "the percentage price rise" [62]. Thus, if we eliminate the influence of inflation, we do not have to forecast price development, but instead can use today's cost level. For small levels of inflation the real rate of interest is approximately equal to the nominal rate of interest minus the inflation rate.

The applied rates in system studies almost always are greater than what corresponds to the prevailing capital costs alone[42]. The difference is attributable to other factors, such as conservatism and risk avoidance. In practice, the used rate is equal to the required rate of return. The rate used in these evaluations is 6 %.

3.4 Linear approximations of costs

Thermal losses are proportional to the square of the current through a component. This fact indicates that the load would have to be allocated to each line segment, and in order to cope with that, the network topology would have to be unambiguously determined. An essential simplification to the evaluation routine is that the costs of network elements can either be assumed constant or have a linear dependence on the load current. This has led to the construction of linear simulations of cost curves.

In network design problems the most important components in this respect are the lines and substations with transformers. The total costs of a line can be divided into three different groups. Each of them is defined per unit length of line. The installation costs consist of the excavation costs for underground cables, or poles and mountings and are nearly independent of the conductor size. The present worth value of operation and maintenance costs also belong in this category. The material costs are dependent on the conductor sizes. The discounted costs of losses depend on the conductor resistance and various parameters to be estimated such as interest rates and the annual increase of load.

The prerequisites of linearization are handled, e.g., in [43]. A sufficient condition is that the material costs of a line are proportional to its cross-sectional area. If this condition is fulfilled, the cost function can be approximated by a straight line.

Similar linear approximations are also needed for substations. Substations consist of several primary units and the respective auxiliary systems and premises. Higher load density leads to larger substations with larger and/or a higher number of transformers and feeders. Thus, a substation cost function is a composite cost function. In the model, the cost of substations is divided according to the primary components of the substation: HV lines, transformers including HV and MV connections and switchgears, and MV lines. All shared costs (land, building, secondary systems including protection, control, telecontrol, auxiliary voltage supply, real estate surveillance, fire protection, etc.) are allocated to these three primary components (Figure 14).

Although it can be argued whether linearization in this case would be appropriate[43], the substation paretos★ in Appendix 5 show that, using these composite cost functions, a fairly good linear approximation is reached, keeping in mind the accuracy needed in this sort of study. The set of

★ After the Italian scientist Vilfredo Pareto (1878-1923), known for his theory on mass and elite interaction as well as for his application of mathematics to economic analysis.

substation cost functions is composed of configurations with 1 or 2 infeeding 110 kV lines and 1…5 transformers. Underestimation of cost is probably greater in the case of substations, since several reasons - in addition to the discontinuous nature of the individual composite functions - lead up to a deviation from the pareto line, e.g., use of standard size transformers and standard transformer and switchgear configurations in order to maintain operational rationality in distribution systems.

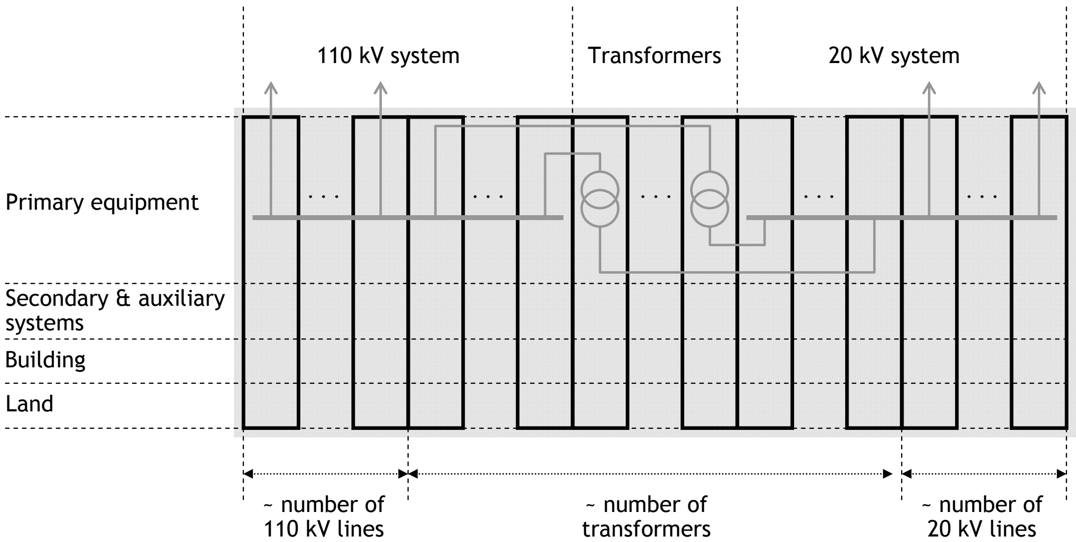


***Figure 14**. Composition of substations.*

The cost of MV feeders is not part of the substation cost. The number of MV feeders at the substation and their respective cost are determined as part of the MV feeder system calculation.

For the switches in a distribution network (MV level), the costs of automated or manual switches are required. These will be handled in Chapter 5. Switches at substations are included in substation switchgear costs.

The equipment at the customer connection level is not included except for the connecting line.

By using linear cost functions we remove the need to allocate load to individual line segments. We also cover the whole set of components instead of modelling each rating of a component group. The line length can be approximated without generating a detailed network topology, and the load related costs can be calculated by determining the centre point of load. The total load is then assumed to be transferred from that point to the supply point.[42] Thus, linearized functions are ideal for a model using homogeneous supply areas and geometric modelling.

For each structural area category and component type, a linear approximation will be composed using the cost functions for individual components (Figure 15).

To be able to analyze the cost structure in different areas, the fixed component f will be divided into three portions: (1) f_1 represents the minimum cost conductor or primary component set at substations, (2) f_2 represents the additional cost of conductors or other components, e.g., the price difference between the minimum cost and the minimum cost overhead line conductor, (3) f_3 represents the cost of supporting and protective structures, i.e., poles in OHL networks and trenching in cable networks and the cost of buildings. The minimum fixed cost of supply will be estimated using the minimum costs f_1 and f_{3min}.

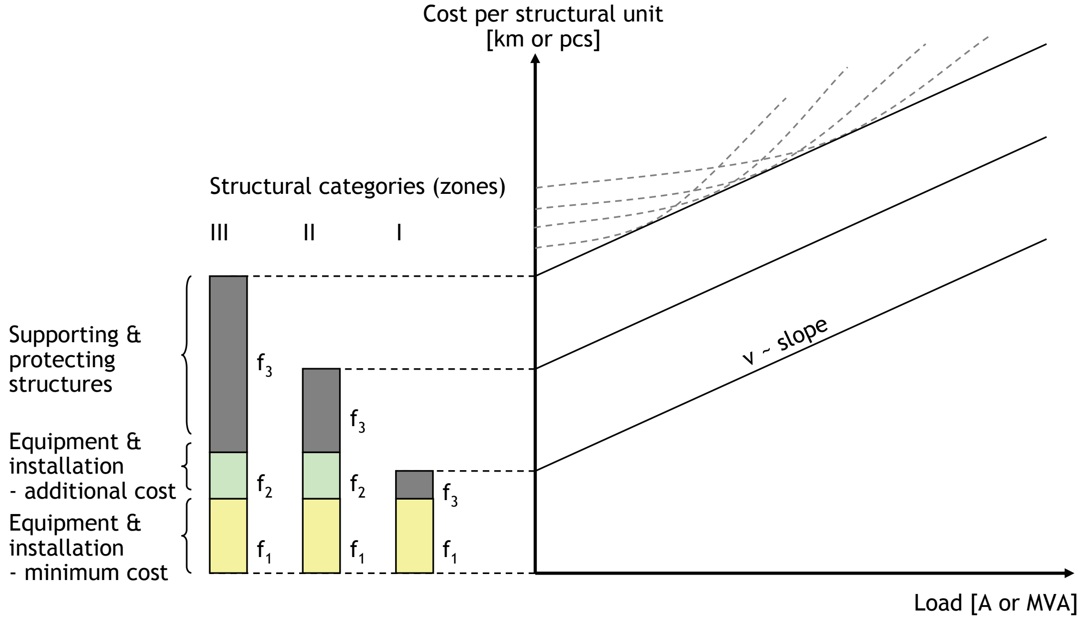


Figure 15. *Forming of linear approximations for structural categories.*

The load related costs, i.e., costs of higher rated components and load losses, will be determined by the load per unit multiplied by the factor *v*.

The described division of costs is quite rough, but it enables the fast generation of a general view of the cost structure.

The component data and linear approximations are summarized in Appendices 4 (line and substation data and unit costs), 5 (linear approximation diagrams with cost parameters and other variables) and 6 (summary of the parameters for the linear approximation functions).

4 NETWORK MODELS

4.1 The objective of network modelling

The objective of this thesis is to determine the cost structure and the effect of cost-raising factors at the system level in different environments. As the need is to study the effect of the external factors on the network cost, it should be possible to parameterize these factors into the model. The factors to be included in the model were analyzed in Chapter 2. A further objective is to elucidate the cause-effect mechanisms to support the interpretation of statistical and other approaches. Therefore an analytical approach is preferable.

Planning of transmission and distribution systems involves various tasks. The planning object may either be a single component or the whole system (or subsystem). In this study, there is no need to carry out any component specific design. In system level studies, the components are described as groups (lines or stations) represented by linear cost function approximations. Understanding of the structural design types and their features, however, is essential. Even though individual components are not considered, the method used has to generate a target network with the right volume of different components.

An absolute requirement is the voltage level comprehensive planning and optimization, because the aim is to study the total cost covering the whole system, from the HV level to the LV connection points.

One aspect in network planning is the time frame and the course of events during the studied period, i.e., the dynamics. In a static model (horizon year or single period model) the optimal target network is first determined for the last year of the planning period by applying some static planning method using fixed given values. A multistage development plan is then determined so that only the investments included in the optimal plan for the last year are allowed. In dynamic models (considering events within a period or several periods) all the decisions relating to the development of the network throughout the planning period are taken into account simultaneously. The objective is to minimize the total cost over a certain period of time and not aim at an optimal network in a certain year.[63]

Dynamic modelling is not considered necessary in this case. When the rate of load growth is in the range of 0…2 % the transition in load density is only slight and the cost structure does not change significantly unless there is a change in construction environment. This is the case when a relatively large area is examined. In a smaller area relatively dramatic load growth and drastic changes can occur, but in that case we can treat an area as a new electrified area and a situation resembling a greenfield case. In such a situation, the network is built within a few years and the transition phase is not so significant.

In the process of aiming towards the target network there are always some non-optimal intermediate phases whose remnants appear in the final state network as non-ideal solutions compared to greenfield solutions. These factors are discussed in Chapter 7.

The primary target here is that the result should reflect the cost structure of present network masses, and not to create an investment program. The evaluation method should also be as simple as possible. Therefore a static model is chosen.

Here, a similar approach is used as in [33], where temporally constant structural characteristics are assumed for each single supply area. Neglecting the residual values and assuming a cyclical renewal of the operational equipment at the end of the usual operating life, the evaluation can be based on the annual network costs, independent of the considered time. Since real networks and their repurchase values are used as a reference, the horizon year target network fitted into its respective environment and load density is suitable for comparison.

The chosen model network approach using a static single-period model and generating a horizon year optimal and idealistic target network is suitable for evaluation of system level solutions[44,45]. Enumeration of all feasible network solutions within given constraints is carried out until the one solution with the minimum value of the objective cost function is found. This is possible only if the number of controlled parameters is fairly low. The cost of the resulting idealistic network is an underestimate of the real cost.

An alternative method could be mixed integer optimization, because a network problem with fixed cost component can be solved using it. The mixed integer optimization method is suitable for solving the locations of new substations, and finding line routes[63]. The chosen method contains certain features from mixed integer optimization, direct search and analytical methods.

In addition to external environmental factors (Chapter 2) and linear approximations of costs (Chapter 3), electrical constraints (Section 4.2) and an analytic geometric model (Section 4.3) are required.

4.2 Electrical boundary conditions

An electrical installation has to fulfil the requirements of dielectric and mechanical withstand, and withstand the thermal and mechanical effects caused by load and fault currents to ensure the protection of persons and property, and operational reliability. The voltage quality level at the customer connection must be ensured and the voltage must be kept within the allowed range. The evaluation parameters and technical constraints are presented in Appendix 7.

▪ ***capacity – thermal limit***

The maximum capacity of equipment is determined by the maximum temperature allowed for the conductor, the insulation or the environment. Due to the short duration of a short circuit, the allowed temperature is higher than the temperature during normal operation with load currents. If the peak utilization time is very short, the economic rating may lead to a too high temperature rise in normal operation. In abnormal operational situations, e.g., during reserve connection in a redundant system, the thermal limit may become a constraint. The need for reserve capacity, or 'network strength'[42], has to be taken into account when determining the thermal capabilities of the components. This could have an effect both on cross-sectional areas and the number of feeders or transformers. For a short period of time, a higher loading may be allowed for the equipment. In cable installations, parallel cables, the soil thermal properties and other heat sources in the vicinity of the cable route reduce the capacity of the cable.

The maximum continuous load currents of lines are presented in Appendix 4. For transformers, the maximum continuous load is 1,5 times the nominal power as a standard. In practice the transformer loading is limited to 1,2…1,3 times the nominal rating. When using the paretos, we have to set the thermal limit of the largest unit as a constraint in the network generation procedure.

▪ ***voltage drop***

The total voltage drop between the controlled voltage source and the connection point is the sum of the voltage drops of the lines and transformers between these points. These voltage drops depend on the impedances of the lines and transformers and the load current passing through them. The nearest controlled point is usually the main transformer at the HV/MV substation. The lengths of MV lines vary in quite a large range and thus a constant per kilometre voltage drop is not a good constraint measure. It has been proven[43] that economic conductor sizes lead to a constant voltage regulation per unit length independent of the load profile along the MV line.

The maximum voltage drops allowed used in this study are 6 % in LV networks and 4 % in MV networks.

▪ ***operational values of protection***

The magnitude of fault currents compared to the component withstand level, allowed hazard voltages and the operational values of protection devices form an entanglement of constraints in network design. The fault current must not be too high (short circuit withstand, hazard voltages), but on the other hand it has to be large enough to ensure the reliable operation of protection devices. Especially in LV networks, the fast functioning of protection following a single-phase fault is an important constraint setting limits for the LV system design.

▪ ***checking the impact of capacity, voltage drop and protection limit constraints***

The above described constraints can be graphically presented in a single figure. In Figure 16 these constraints are presented as a function of transmission distance and transmitted power. Using these constraints the maximum range of, for instance, an MV/LV station can be determined. In the evaluation procedure, these three limits are checked.

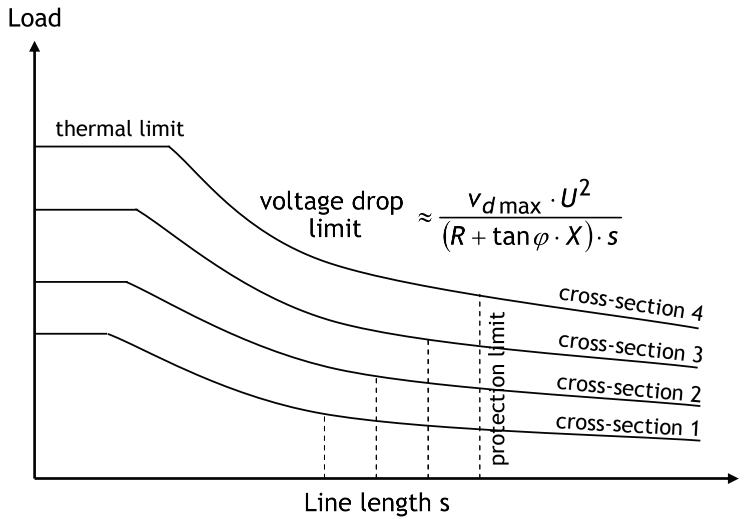


***Figure 16**. The impact of different constraints. The vertical line represents the protection limit. The curved line represents the voltage drop limit (v_{dmax} = maximum voltage drop allowed). The horizontal line represents the thermal limit (or economic limit, the interest rate and rate of load growth as parameters).*

▪ ***short circuit withstand***

The level of detail in this study is such that the short circuit ratings of individual components will not be considered. As load density increases, larger cross-sectional areas and larger unit sizes are applied. These also have higher short circuit withstand levels (see, e.g., Appendix 4). Therefore, at the level of detail / robustness of this system level study, it is assumed that the short circuit withstand level is automatically adjusted and taken into account in component cost, and thus a separate check is not necessary. However, the lower voltage switchgear short circuit withstand level is checked at transformer stations and substations where the maximum value occurs.

▪ ***reactive effect***

Capacitance per unit length is much higher in cables compared to overhead lines. This capacitance has several important impacts on system design and operation. The capacitive reactive power produced in the line has an impact on the reactive power balance and volt-var behaviour of the feeder and the whole distribution system. The large charging current of cable networks may also hinder the operation of MV network disconnectors even in a lightly loaded system. The most significant impact is that the zero sequence capacitance determines the earth fault current of the galvanic system. In MV cable systems the earth fault current in a metallic fault is 50-fold compared to the earth fault current in overhead systems with the same total length.

As the feeder length and the total length of the MV feeder system is known, using the positive sequence and zero sequence capacitances it is possible to evaluate the needs and costs for reactive power compensation and earth fault current compensation and/or earthing impedance requirements.

The earth fault currents per unit length of MV and HV lines are presented in Appendix 4.

4.3 Analytic network model

Starting from a given load density (substation area energy density ED_{SA}) and the environment (Chapter 2) the analytic model should generate the number of connection points, their peak demands and the distances between them. Using geometric rules, the network is generated between these points and thus the total network length is yielded. In addition, the loadless areas ('open space') – most relevant at the MV feeder system level - have to be modelled in order to simulate the concentration of load. This feature is important since geographical concentration reduces the total network length and alters the relation between LV and MV line lengths.

In order to keep the model analytic and simple, it has to be geometrically symmetrical. This way, only a part of the network needs to be evaluated – for instance one MV feeder which is similar to the others – and the equal distribution of similar stations can be determined. In principle, the networks can be divided into homogeneous subareas, which in turn could be different from each other and thus some heterogeneous features could be studied. Periodic recurrence of similar areas is however a requirement to constitute similar substation service areas.

▪ ***LV system and MV/LV station service area***

Energy density ED_{LV} at the transformer station service area level is

$$ED_{LV} = \frac{ED_{SA}}{(1 - A_{MVC}) \cdot (1 - \omega)} \qquad \textbf{\textit{Eq. 17}}$$

where

ED_{SA} = energy density of substation service area
A_{MVC} = per unit share of the substation area of MV customer loads
ω = per unit share of open space of the substation service area

For a certain distance between transformer stations $DBTS$ (see Figure 17):

$$A_{TS} = DBTS^2 \qquad \textbf{\textit{Eq. 18}}$$

$$E_{TS} = ED_{LV} \cdot A_{TS} \qquad \textbf{\textit{Eq. 19}}$$

where

A_{TS} = transformer station service area
E_{TS} = annual energy of the transformer station

Knowing the annual energy of the area E_{TS}, the number of customers NC_{LV} and connection points NCP_{LV} of each customer group and consequently the total connection point density CPD_{LV}, the average distance between connection points $DBCP_{LV}$ can be determined based on the customer mix:

$$NC_{LV} = \sum_{r=1}^{n_r} \frac{\varepsilon_r \cdot E_{TS}}{E_r} \qquad \textbf{Eq. 20} \text{ and } \qquad NCP_{LV} = \sum_{r=1}^{n_r} \frac{\varepsilon_r \cdot E_{TS}}{n_{cpr} \cdot E_r} \qquad \textbf{Eq. 21}$$

$$CPD_{LV} = \frac{NCP_{LV}}{A_{TS}} \qquad \textbf{Eq. 22}$$

$$DBCP_{LV} = \sqrt{\frac{A_{TS}}{NCP_{LV}}} = \sqrt{\frac{1}{CPD_{LV}}} \qquad \textbf{Eq. 23}$$

where

ε_r = per unit share of user group r of the total energy
n_{cpr} = number of customers per connection for user group r
E_r = normalized annual energy of user group r customer

Using the simple model in Figure 17 the length of lines per transformer station can be evaluated using the distance between connection points. On the transformer station service area the load is homogeneously distributed and the evenly distributed LV connection points form a grid (Figure 17). The order of connection is of no importance since the adjacent connection points are all at the same distance and linearized cost functions are used. Additionally, for each connection, a connection line of length L_{CP} (~ few tens of meters) is added. The theoretical minimum length using straight line connections between connection points has to be multiplied by the line length adjusting factor *LLAF* to end up with realistic line lengths.

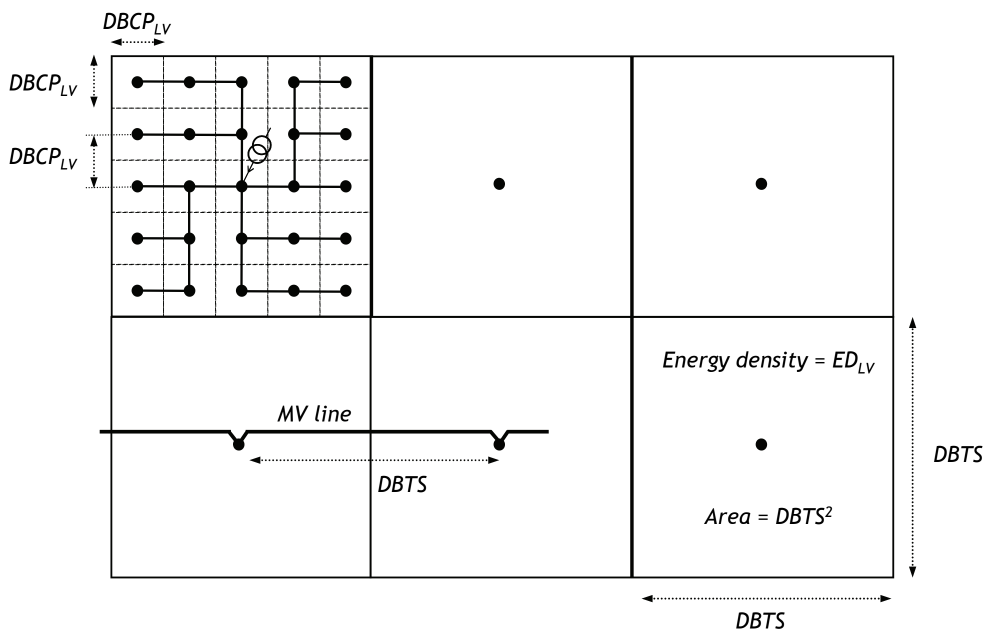


Figure 17. *LV network model in a homogeneous area. DBCP = distance between connection points, DBTS = distance between transformer stations.*

Assuming that one connection point is directly fed by the transformer station the line length of the LV feeders LL_{LV} is:

$$LL_{LV} = (NCP_{LV} - 1) \cdot DBCP_{LV} \cdot LLAF_{LV} + NCP_{LV} \cdot L_{CP} \qquad \textbf{\textit{Eq. 24}}$$

The maximum LV feeder length is

$$L_{LV\max} = (DBTS - DBCP_{LV}) \cdot LLAF_{LV} + L_{CP} \qquad \textbf{\textit{Eq. 25}}$$

Within a coherent area of LV load the MV network length per transformer station is:

$$LL_{MV,TS} = DBTS \cdot LLAF_{MV} \qquad \textbf{\textit{Eq. 26}}$$

The maximum demand of the transformer station P_{TS} is obtained using equation 6. The apparent power

$$S_{TS} = \frac{P_{TS}}{\cos\varphi} \qquad \textbf{\textit{Eq. 27}}$$

To calculate the load dependent cost, we have to define the average transmission distance L_{TFLV} for the LV feeders and their respective loads. Since the network topology is not known, an equivalent load centre distance is determined. The load centre distance is represented as the centre of gravity of a feeder service sector[44]. An estimate of 2/3 x the radius (~DBTS/2) of the sector is used. The feeder peak demand P_{FLV} depends on the number of feeders and is calculated using equation 6. Thus:

$$L_{TFLV} \approx \frac{2}{3} \cdot \frac{DBTS}{2} \cdot LLAF_{LV} \qquad \textbf{\textit{Eq. 28}}$$

The network life cycle cost is finally evaluated using the linear pareto functions:

$$LCC_{PW,LV} = (f_{1LV} + f_{2LV} + f_{3LV}) \cdot LL_{LV} + v_{LV} \cdot N_{FLV} \cdot I_{FLV}(S_{TS}, N_{FLV}) \cdot L_{TFLV} \qquad \textbf{\textit{Eq. 29}}$$

$$LCC_{PW,TS} = f_{1TS} + f_{2TS} + f_{3TS} + v_{TS} \cdot S_{TS} \qquad \textbf{\textit{Eq. 30}}$$

$$LCC_{PW,MV} = (f_{1MV} + f_{2MV} + f_{3MV}) \cdot LL_{MV,TS} + v_{MV} \cdot I_{MV}(S_{TS}) \cdot DBTS \qquad \textbf{\textit{Eq. 31}}$$

where

f_1, f_2. f_3 and v are cost parameters according to Figure 15 and Appendix 6
N_{FLV} = the number of low voltage feeders
I_{FLV} = LV feeder current depending on the number of LV feeders and the total TS load
I_{MV} = MV feeder current depending on the total TS load

This calculation is repeated for a series of *DBTS* values and finally the value giving the minimum annualized cost of the transformer station service area per average energy delivered per year will be searched.

$$C_{a,TSA} = \frac{LCC_{PW,TOT}}{DF_1 \cdot E_{TS} \cdot AEF} = \frac{LCC_{PW,LV} + LCC_{PW,TS} + LCC_{PW,MV}}{DF_1 \cdot E_{TS} \cdot AEF} \qquad \textbf{Eq. 32}$$

where AEF = average energy factor taking into account the load growth.

The minimum is observed within the range of solutions fulfilling the technical constraints.

▪ ***MV feeder system and HV/MV substation service area***

In the formulation of the substation service area model the basic element is a circle with a radius r and its sector with an angle $\theta = 2\beta$ representing the service area of an MV feeder (Figure 18). The sector angle is a function of the number of feeders:

$$\theta = \frac{2\pi}{N_{FMV}} = 2\beta \qquad \textbf{Eq. 33}$$

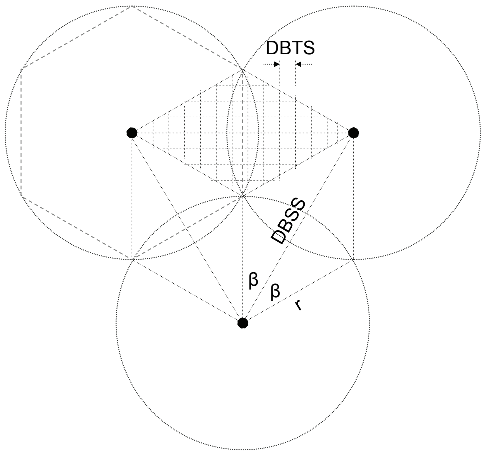


Figure 18. *Basic elements in substation and feeder service area modelling. DBSS = distance between substations, DBTS = distance between transformer stations.*

In the sector area the load is homogeneously distributed and evenly distributed transformer stations with a distance DBTS between them form a grid of MV/LV stations. In the number of transformer stations not only the MV/LV stations are taken into account but also the MV customers' connection points have to be considered.

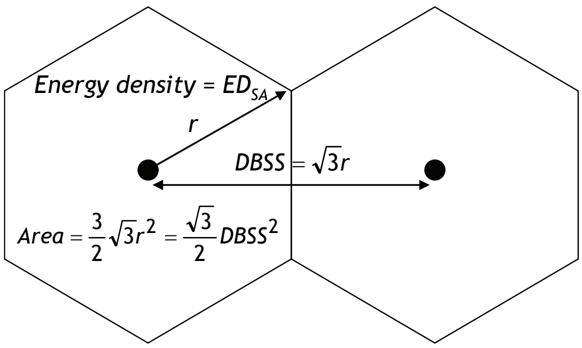


Figure 19. *Geometric model for the service area of a HV/MV substation.*

Together with the neighbouring substations the whole area will be covered and the substation area is best described as a polygon; the most convenient form for modelling is usually a hexagon[41,42,44].

For a certain distance between substations *DBSS*:

$$A_{SS} = \frac{\sqrt{3}}{2} DBSS^2 \qquad \textbf{Eq. 34}$$

$$E_{SS} = ED_{SA} \cdot A_{SS} \qquad \textbf{Eq. 35}$$

where

A_{SS} = substation service area
E_{SS} = annual energy of the substation

The maximum demand of the substation P_{SS} is obtained using equation 6. The apparent power

$$S_{SS} = \frac{P_{SS}}{\cos\varphi} \qquad \textbf{Eq. 36}$$

The minimum required number of MV feeders N_{FMV} can be determined by the maximum load of a feeder S_{FMVmax}:

$$N_{FMV} = \max\left[N_{FMV\,\min}; \frac{S_{SS}}{S_{FMV\,\max}}\right] \qquad \textbf{Eq. 37}$$

where N_{FMVmin} is 4 for urban substations and 3 for rural substations.

The service area of an MV feeder is

$$A_{FMV} = \frac{A_{SS} \cdot (1-\omega)}{N_{FMV}} \qquad \textbf{Eq. 38}$$

The total number of MV connection points, i.e., the number of transformer stations is

$$N_{TStot} = \frac{(\varepsilon_{SERVCMV} + \varepsilon_{INDCMV}) \cdot E_{SS}}{E_{rMV}} + \frac{(1 - \varepsilon_{SERVCMV} - \varepsilon_{INDCMV}) \cdot E_{SS}}{E_{TS}} \qquad \textbf{Eq. 39}$$

where

$\varepsilon_{SERVCMV}$ = per unit share of user group SERVCMV of the total energy
$\varepsilon_{SERVCMV}$ = per unit share of user group INDCMV of the total energy
E_{rMV} = normalized annual energy of MV customers

The number of MV connection points per MV feeder is

$$N_{TS,FMV} = \frac{N_{TStot}}{N_{FMV}} \qquad \textbf{Eq. 40}$$

and the distance between MV connection points or the resulting distance between transformer stations (including MV customers):

$$DBTS_{tot} = \sqrt{\frac{A_{FMV}}{N_{TS,FMV}}} \qquad \textbf{Eq. 41}$$

The sector model can be applied both to rural and urban type networks (Figure 20).

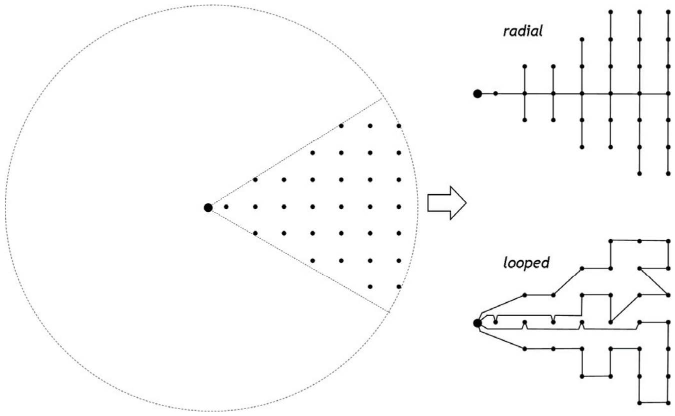


***Figure 20**. Application of sector model to rural type radial network and urban type looped network.*

Again assuming the transformer stations to be evenly distributed, the length of MV network can be calculated simply by connecting each transformer station to another or to the substation (all the adjacent stations are all always at the same distance). Thus the MV network length is in case of a radial network is

$$LL_{MV,radial} = N_{TStot} \cdot DBTS_{tot} \cdot LLAF_{MV} \qquad \textbf{Eq. 42}$$

The maximum length of MV lines in a radial system is

$$L_{MV\max radial} = r \cdot (\cos\beta + \sin\beta) \cdot LLAF_{MV} \qquad \textbf{Eq. 43}$$

where r = radius, see Figure 18

In a looped network there is an additional connection between radial feeders and the line length is

$$LL_{MV,looped} = \left(N_{TStot} + \frac{N_{FMV}}{2} \right) \cdot DBTS_{tot} \cdot LLAF_{MV} \qquad \textbf{Eq. 44}$$

The maximum feeder length in a situation where the whole loop is fed from one end only is

$$L_{MV\max looped} = \frac{LL_{MV,looped}}{N_{MVloops}} = \frac{LL_{MV,looped}}{N_{FMV}/2} \qquad \textbf{Eq. 45}$$

Particularly in rural areas the share of open space (loadless areas) is significant and ignoring the load concentration would lead to too high a line length. Apparently the distribution of open space is sporadic, but as already mentioned in Chapter 2, the load is concentrated around the road network. If the substation is located near a village or small town, the road network leads radially away from the substation. The load is concentrated in the sectors of radial road connections while the other sectors in between are loadless. After some distance there are, however, transversal orbital or perimeter roads. The load is also concentrated along these radial and perimeter roads. Using a sectoral-zonal model based on the road network grid with recurring loadless and loaded zones and sectors, it is possible to simulate load distribution in rural and suburban environments. In urban environments the share of open space is relatively small, but parks or pools within urban areas can be taken into account using the same model (even though the parks have lighting and are not completely without load). It is natural that the sectors of neighbouring substations converge as they follow the same connecting road system.

In Figure 21 the correlation between road network density *RD* and energy density is presented. The data is based on Finnish road network statistics[64] and population density assuming that per capita consumption of electricity is 7 MWh/year. The road network density (km/km^2) is approximated for a given energy density (GWh/km^2) using the following equation (the curve in Figure 21):

$$RD \approx 0{,}7822 \cdot ED^{0{,}3458} \qquad \textbf{Eq. 46}$$

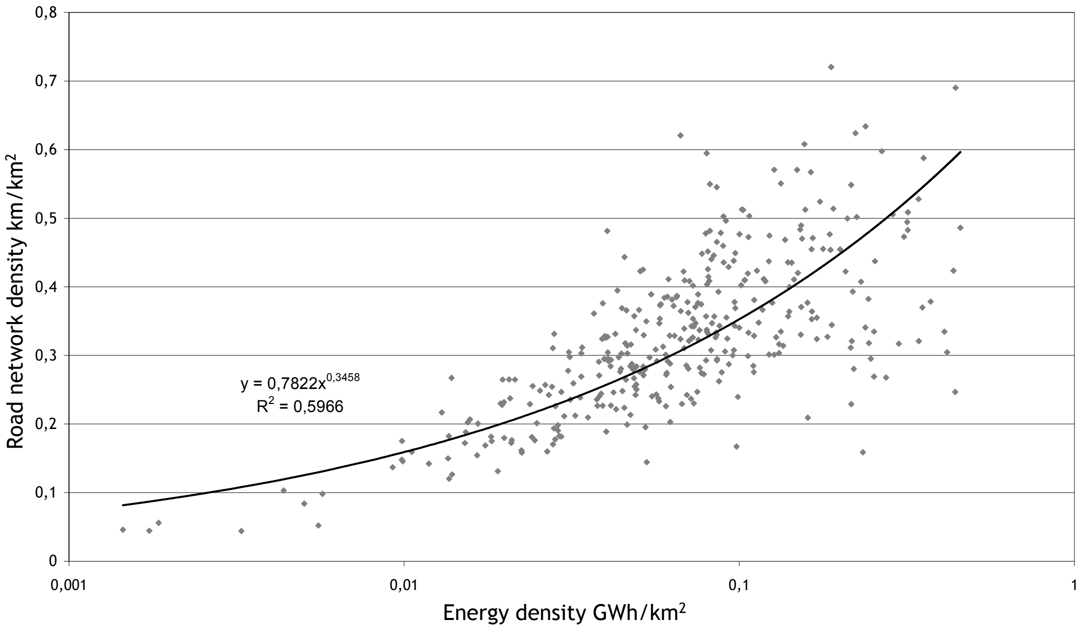


Figure 21. *Correlation between road network density and energy density.*

Assuming that the main road network is concentrated in the MV feeder sectors, the total MV feeder length of a substation service area is the sum of the MV trunks along the roads and the lines connecting each transformer station to the network:

$$LL_{MV,radial} = A_{SS} \cdot RD + N_{TStot} \cdot DBTS_{tot} \cdot LLAF_{MV} \qquad \textbf{Eq. 47}$$

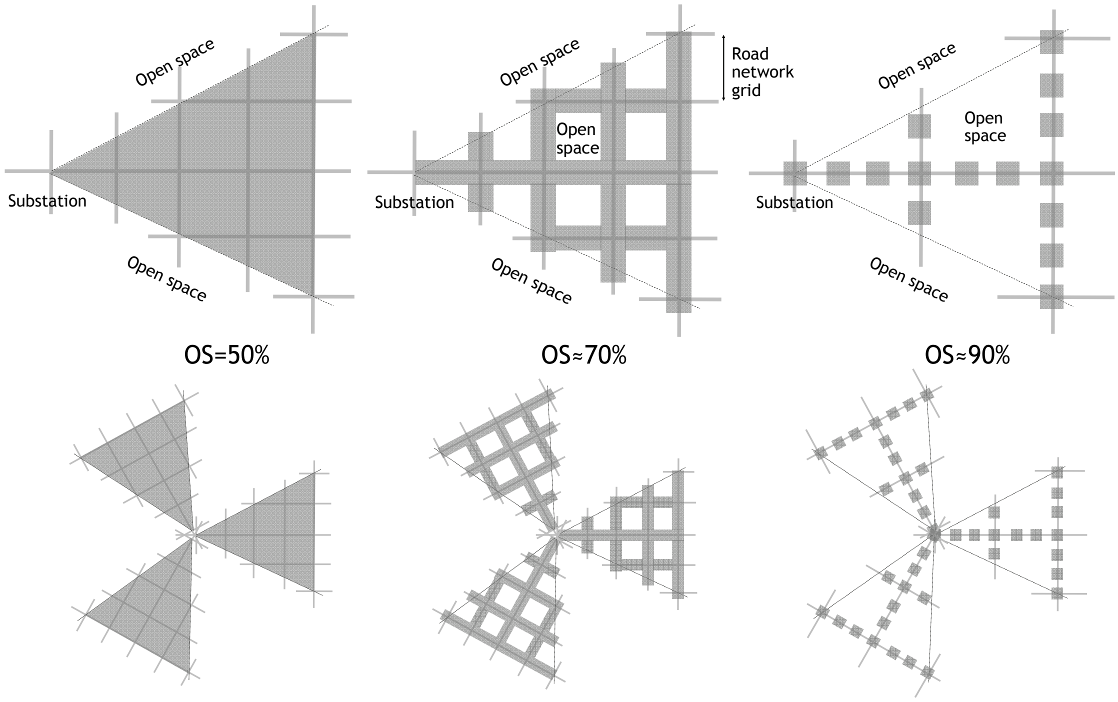


Figure 22. *Description of loadless areas using road network infrastructure as a reference grid; load is concentrated along the roads (shaded area).*

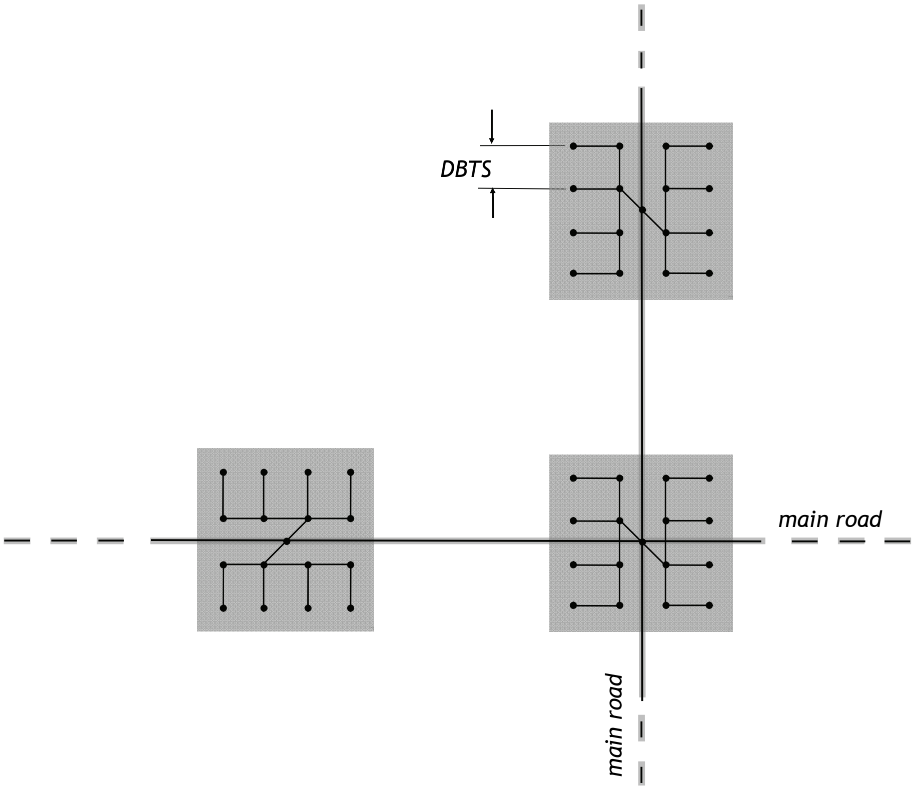


Figure 23. *Medium voltage lines in a segmented feeder service area.*

To calculate the load dependent cost, we have to determine the centre of load within the MV feeder service area. In the case of a triangle-shaped area the transmission distance is

$$L_{TFMV} \approx \frac{2}{3} \cdot r \cdot \cos\beta \qquad \textbf{\textit{Eq. 48}}$$

If segmented load areas are used the same laws can be applied as when calculating the centre of mass.

In the case of a primary substation fault, the neighbouring substations have to feed the load. For this reason, each substation needs to have reserve power. If the neighbouring substations are equal in size, this reserve power can be expressed as the per unit share ρ (0…1) of the total transformer capacity of one substation. In this case the maximum load per substation is

$$S_{SS\max} = (1+\rho) \cdot LD \cdot \frac{\sqrt{3}}{2} \cdot DBSS^2 \qquad \textbf{\textit{Eq. 49}}$$

where LD = power density (MVA/km^2)

and thus the maximum distance between substations in the case of hexagonal service areas is reduced to

$$DBSS_{\max} = \sqrt{\frac{S_{SS\max}}{LD}} \cdot \sqrt{\frac{2}{\sqrt{3}}} \cdot \sqrt{\frac{1}{1+\rho}} \qquad \textbf{\textit{Eq. 50}}$$

Sometimes the maximum substation size is limited to avoid common mode risks at any one supply point. The MV feeder system capacity also limits the reasonable substation size. The required reserve has to be taken into account in the above manner.

The HV network length per substation is:

$$LL_{HV,SS} = DBSS \cdot LLAF_{HV} \qquad \textbf{\textit{Eq. 51}}$$

Network cost is finally evaluated using the linear pareto functions:

$$LCC_{PW,MV} = (f_{1MV} + f_{2MV} + f_{3MV}) \cdot LL_{MV} + v_{MV} \cdot N_{FMV} \cdot I_{FMV}(S_{SS}, N_{FMV}) \cdot L_{TFMV} \qquad \textbf{\textit{Eq. 52}}$$

$$LCC_{PW,MVbays} = (f_{1MVBays} + f_{2MVBays} + f_{3MVBays}) \cdot N_{FMV} \qquad \textbf{\textit{Eq. 53}}$$

$$LCC_{PW,SS} = f_{1SS} + f_{2SS} + f_{3SS} + v_{SS} \cdot S_{SS} \qquad \textbf{\textit{Eq. 54}}$$

$$LCC_{PW,HV} = (f_{1HV} + f_{2HV} + f_{3HV}) \cdot LL_{HV,SS} + v_{HV} \cdot I_{HV}(S_{SS}) \cdot DBSS \cdot LLAF_{HV} \qquad \textbf{\textit{Eq. 55}}$$

where

f_1, f_2. f_3 *and* v are cost parameters according to Figure 15 and Appendix 6
I_{FMV} = MV feeder current depending on the number of feeders and the total SS load
I_{HV} = HV feeder current depending on the total SS load

This calculation is repeated for a series of *DBSS* values and finally the value giving the minimum annualized cost of the substation service area per average energy delivered per year within the set constraints is obtained.

$$C_{aSSA} = \frac{LCC_{PW,TOT}}{DF_1 \cdot E_{SS} \cdot AEF} = \frac{LCC_{PW,MV} + LCC_{PW,MVbays} + LCC_{PW,SS} + LCC_{PW,HV}}{DF_1 \cdot E_{SS} \cdot AEF} \quad \textbf{Eq. 56}$$

The minimum is observed within the range of solutions fulfilling the technical constraints.

▪ ***110 kV system and EHV/HV substation service area***

110 kV network is modelled in two parts. Radial (or open loop) incoming 110 kV feeders are modelled using the distance between substations and the distance from the meshed network. The meshed part is modelled using a standard size EHV/HV substation and the load density of the area.

Depending on the load density and geography, supplies may be provided by single or double circuit transformer feeders or by substations looped into the HV circuits.[53] Typically, in rural environments the substation density is so sparse and size so small that T-connected transformers are the only feasible solution. The neighbouring substations back-up each other, which sets limits to the number of T-connected transformers fed from the same protection zone of a 110 kV main line, i.e., per pair of 110 kV circuit breakers there can not be more than two to three transformers. Similarly, in urban environments where the substations have more than one transformer backing up each other, only two or three of these substations can be connected to the same looped HV distribution line. These substations also have their own 110 kV switchgear providing fully selective protection for the multitransformer substation system.

It must be noticed that in larger cities the meshed transmission system resides within the city area, which has a cost-relevant effect on the feeding HV system (Figure 24).

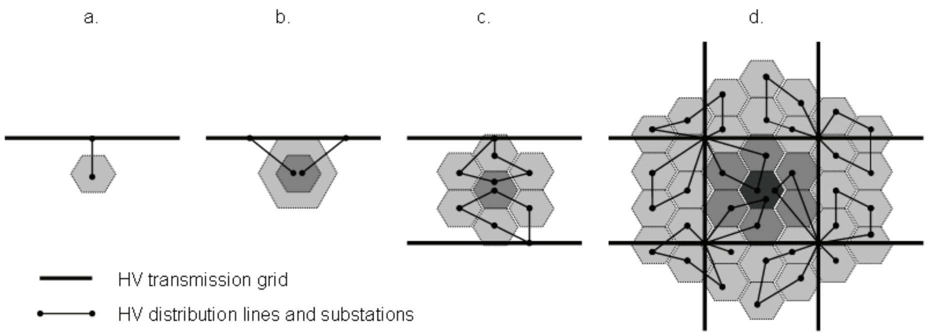


Figure 24. *Feeding HV/MV substations from the meshed transmission system in different environments: a) village b) small town c) medium sized town d) large city.*

Based on the above and Figure 25, we can assume that, independent of the environment, the length of the infeeding 110 kV distribution lines is on average the distance between substations multiplied by the respective line length adjustment factor:

$$LL_{HV,distribution} = LLAF_{HV} \cdot DBSS \quad \textbf{Eq. 57}$$

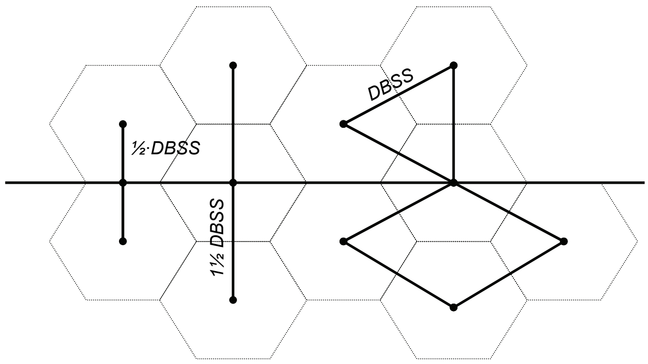


Figure 25*. Modelling the infeeding 110 kV lines.*

The life cycle cost of HV radial lines was already calculated in equations 55 and 56.

The model for the meshed 110 kV system is based simply on the standard size of an EHV/HV substation. Knowing the transformer size and the area energy density, the maximum distance between EHV stations can be calculated as follows.

Taking into account the reserved capacity for disturbances, the maximum load for the EHV/HV station for a certain energy density *ED* and distance between EHV stations *DBEHVS* is

$$S_{EHVS,\max} = (1+\rho)\cdot\frac{ED}{5000h}\cdot\frac{\sqrt{3}}{2}\cdot DBEHVS^2 \qquad \textbf{Eq. 58}$$

From this we can calculate the maximum distance between EHV stations:

$$DBEHVS_{\max} = \sqrt{\frac{S_{EHVS,\max}\cdot 5000h}{ED}}\cdot\sqrt{\frac{2}{\sqrt{3}}}\cdot\sqrt{\frac{1}{1+\rho}} \qquad \textbf{Eq. 59}$$

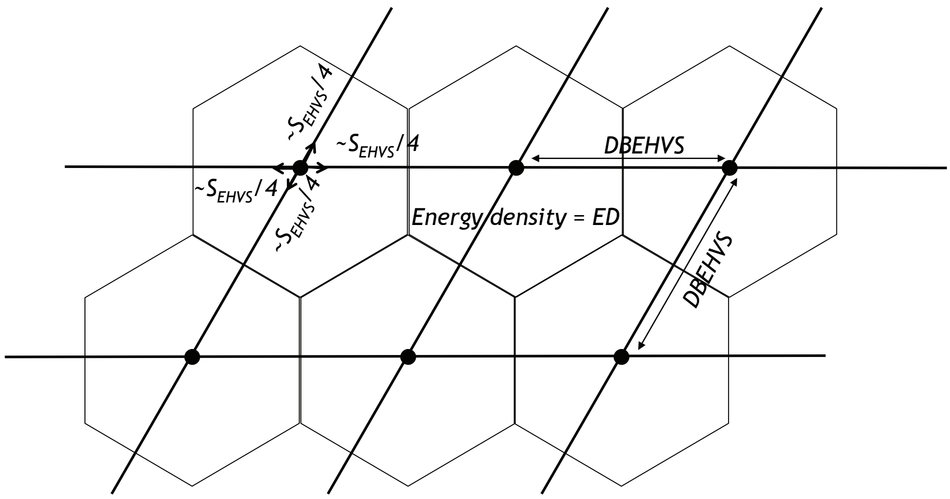


Figure 26*. Model for the 110 kV meshed network based on the distance between EHV/HV substations and standard size EHV/HV stations.*

Based on the configuration in Figure 26 the length of the 110 kV meshed system per EHV station is:

$$LL_{HV,transmission} = 4 \cdot \frac{DBEHVS}{2} \cdot LLAF_{HV} \qquad \textbf{Eq. 60}$$

The HV transmission system life cycle cost is evaluated using the linear pareto function:

$$LCC_{PW,HV} = \left(f_{1HV} + f_{2HV} + f_{3HV}\right) \cdot LL_{HV} + v_{HV} \cdot I_{HV}\left(S_{EHVS}\right) \cdot \frac{DBEHVS}{2} \cdot LLAF_{HV} \qquad \textbf{Eq. 61}$$

Finally, the annualized cost of the EHV station service area per average energy delivered per year is calculated:

$$C_{aEHVSA} = \frac{LCC_{PW,HV}}{DF_1 \cdot E_{EHVS} \cdot AEF} \qquad \textbf{Eq. 62}$$

4.4 Model network evaluation procedure

In the evaluation a so-called bottom-up approach is used, starting from low voltage connection points. For each structural area type and customer mix (discrete parameters), the substation service area energy density (continuous parameter) is varied and optimal MV/LV station and HV/MV substation densities are respectively determined using a direct search. The network volume for the optimum station densities are observed and the respective total cost is calculated. Finally, the 110 kV meshed network cost is added, defined by the standard size of an EHV/HV substation service area. For a certain substation area load density value, the local load densities vary depending on the share of open space (i.e., the concentration level of the load) and the share of MV customers.

The procedure starts from the given energy density value. Based on this and the customer mix in the examined area, the customer and connection point densities are calculated. This then is the basis for the bottom-up network generation procedure.

The optimum station densities are searched in two phases, each involving the lower voltage feeder system, transforming stations between voltage levels, and the higher voltage infeeding line(s). The optimum distance is determined by the minimum annualized total cost per energy delivered:

$$C_{a\min} = \min \sum \left(C_{a,LowVoltageSystem} + C_{a,Transformation} + C_{a,HighVoltageSystem}\right) \qquad \textbf{Eq. 63}$$

The minimum is observed within the range of solutions fulfilling the technical constraints.

Consequently, the network volume serving the customers defined by the energy density of this particular area has been determined. The network volume and the cost structure are stored together with all the predetermined and calculated parameters. After repeating this procedure for different energy densities and typical areas, a set of data for further analysis is produced. Correlation analysis between the cost and the different parameters is then carried out.

Since the analytic model is fairly simple, a standard spreadsheet solution is used with a task flow as shown in Figure 27.

A1. For all structural types (Appendix 3)

B1. For the defined energy density range (Appendix 3)

C1a. Determine the LV connection point density based on energy density and the number of LV customers (Equations 17-23)

C1b. For the defined DBTS (distance between transformer stations) range

C1b1. Determine the network volume (Equations 24-27)

C1b2. Evaluate network cost (Equations 28-32)

C1b3. Search minimum cost DBTS within technical constraints

C1b4. Store data on optimum DBTS

C2a. Determine the MV connection point density based on optimum DBTS and the number of MV customers (Equations 34-41)

C2b. For the defined DBSS (distance between substations) range

C2b1. Determine the network volume (Equations 42-47)

C2b2. Evaluate network cost (Equations 48-56)

C2b3. Search minimum cost DBSS within technical constraints

C2b4. Store data on optimum DBSS

C3a. Determine HV transmission network volume (Equations 57-60)

C3b. Evaluate HV transmission network cost (Equations 61-62)

C3c. Store HV transmission data

A2. Analyze cost structures and levels

Figure 27. *Evaluation procedure.*

5 RELIABILITY ENGINEERING AT THE DISTRIBUTION SYSTEM LEVEL

5.1 Reliability and economies of load density

Reliability engineering is not the focus of this thesis, but since reliability level and outage cost are essential system planning parameters, some basic considerations are presented here. Outage costs are not taken into account in the network generation procedure (presented in Chapter 4) which produces networks resembling those of current practices in different environments (i.e., radial overhead networks in rural environments and open-loop cable networks in urban environments). Improvement of the reliability levels of these networks is considered here separately, which again resembles the situation where the DNOs are today.

The current infrastructure was designed decades ago to serve stand-alone electric loads. Today, information and communications technology (ICT) and the power system are tied to the functions and control of society in a more integrated and global manner. Sensitivity to even slight disruptions in power supply, not to mention longer interruptions, has increased.[65] For this reason, migration strategies towards more reliable networks are important in all environments. The baseline, however, is quite different in different networks and there are several factors directly or indirectly depending on load density:

- Larger unit sizes are economical in areas of higher load density, and thus a single contingency results in a larger outage (energy not supplied, the number of customers)

- The travel times and access to network switching locations (MV/LV stations) depend upon the area type: in rural areas the distances are longer while in densely built city areas the travel times may be long due to traffic.

- Due to the external conditions (see Chapter 2), in the area of high load density shielded structures have to be used (cables, switchgear, buildings). The consequence is that the vulnerability to faults is lower. On the other hand, once the fault occurs, the nature of the fault is different. Depending on the component type, either low fault frequency plus long repair time and more expensive repair, or higher fault frequency and shorter repair time and cheaper repair tend to prevail. This affects the need for redundancy and sectionalizing, which may be different in cable systems compared to overhead systems.

- Vulnerability to common mode faults is very different: in rural overhead systems large disturbances caused by natural phenomena are decisive, while in urban cable systems the importance and relative portion of high voltage and substation faults is significant.

The focus in reliability studies here is in MV feeder systems, which has the most profound impact on the system reliability performance: roughly 80 % of customer interruptions are caused by MV systems[69]. HV systems are planned using strict N-1 contingency criterion, and although outages caused by that network level are wide impact phenomena, they are also very rare due to the high level of redundancy used. On the other hand, the extent of a single outage at the LV system level is restricted and for this reason not studied here. The great majority of the outages are caused by the MV feeder system, because the extent of an radially operated MV feeder, acting as a widespread fault antenna, is quite large, leading to an outage for a great number of customers. Therefore, MV distribution systems largely determine the service quality profile seen by end customers and dominate the overall reliability indices.

5.2 Evaluation of system reliability

▪ ***reliability indices***

The quality of supply can be defined as ‘voltage quality’, referring to the four parameters (frequency, magnitude, waveform, symmetry) and ‘reliability’ or ‘voltage continuity’, referring to long interruptions. The latter is a result of the failure characteristics of a distribution system, which is obtained by assessing the frequency and duration of interruptions (and voltage dips). The extent of the interruptions is measured by the amount of undelivered energy or energy-not-supplied (ENS).

In a radial distribution system, a customer connected to any load point requires all components in series between himself and the supply point to be operating[66]. In this case, the three basic reliability parameters applied to these systems are

▪ *the average failure rate* $$\lambda_s = \sum_i \lambda_i \qquad \textbf{Eq. 64}$$

▪ *the average annual outage time* $$U_s = \sum_i \lambda_i \cdot r_i \qquad \textbf{Eq. 65}$$

▪ *and the average outage time* $$r_s = \frac{U_s}{\lambda_s} = \frac{\sum_i \lambda_i \cdot r_i}{\sum_i \lambda_i} \qquad \textbf{Eq. 66}$$

where

s = series system (radial system)
i = component index
λ = expected failure rate
U = unavailability, outage time
r = mean time to repair

These three basic customer load point indices measure the expected number of outages and their duration for individual customers. They cannot differentiate, for instance, between the interruption of large and small load. System indices such as SAIDI and SAIFI have been established to assess the overall reliability of the system. These indices can be used to compare the effects of various design and maintenance strategies on system reliability. These are calculated for each load point j per each fault i. In the case of homogeneous supply areas, it is adequate to analyze one feeder using homogeneous sections of the MV feeder service area. Further more, in this case the customer-weighted and energy-weighted indices are identical. In the evaluation, the number of customers or energy can be replaced by the number of identical sections.

▪ system average interruption frequency index:

$$\text{SAIFI} = \frac{\text{total number of customer interruptions}}{\text{total number of customers served}} = \frac{\sum_{i=1}^{n} W(i)}{W_{tot}} \qquad \textbf{Eq. 67}$$

▪ System average interruption duration index:

$$\text{SAIDI} = \frac{\text{sum of customer interruption durations}}{\text{total number of customers served}} = \frac{\sum_{i=1}^{n}\sum_{j=1}^{m} W(i,j)\cdot t(i,j)}{W_{tot}} \quad \textbf{Eq. 68}$$

▪ Customer average interruption duration index:

$$\text{CAIDI} = \frac{\text{sum of customer interruption durations}}{\text{total number of customer interrptions}} = \frac{\text{SAIDI}}{\text{SAIFI}} \quad \textbf{Eq. 69}$$

where

i	= interruption
j	= segment of the service area
n	= total number of interruptions
m	= number of segments
W_{tot}	= yearly energy of the service area
$W(i,j)$	= annual energy of the segments affected by the duration $t(i,j)$
$W(i)$	= annual energy of the segments affected by the interruption i
$t(i,j)$	= duration of the interruption i in the segment j

For the evaluation of customer interruption cost, two additional indices are needed, these being the average load disconnected P_{ave} due to a system failure measured in kW or MW and the average energy not supplied *ENS* due to a system failure, measured in kWh or MWh.

$$P_{ave} = \frac{\text{total energy demanded in period of interest}}{\text{period of interest}} = \frac{W_{tot}}{8760\,h} \quad \textbf{Eq. 70}$$

$$ENS = \text{total energy not supplied by the system} = \sum P_{ave(i)} \cdot U_i \quad \textbf{Eq. 71}$$

where $P_{ave(i)}$ is the average load connected to the area affected by the interruption.

▪ ***outage cost – customer interruption cost***

The outage costs in general have two parts: that seen by the utility and that seen by society or the customer[67]. The utility outage cost includes the loss of revenue from customers not served and the increased expenditure due to maintenance and repair. These costs, however, usually form only a very small part of the total outage costs. A greater part of the costs comprises those seen by the customer and most of these are extremely difficult to quantify. Outages in electricity supply can cause extensive economic damage to the customers due to lost production, spoilt raw materials, broken equipment, and various other reasons. The reliability worth of a network may be defined as the benefit to society ascribed to the reliability level of a network. The best measure of reliability worth is therefore given by customer interruption cost (CIC). While the load point and performance indices indicate the frequency, duration, severity and significance of outage situations, reliability worth attaches an economic value to such situations. This is a particularly attractive aspect since this means that their incremental values can be included in the cost-benefit analyses of alternative network configurations.

The worth assessment is based on customer surveys. The obtained survey data can be compiled and calculated for the Sector Customer Damage Function (SCDF), which presents the relationship between the sector interruption cost as a function of interruption duration. Real distribution systems supply different mixtures of commercial, industrial and residential types of customers that impose different load demands and service quality requirements. A composite customer damage function (CCDF) must be defined as the estimate of costs associated with power interruptions as a function of the interruption duration for the customer mix in a particular service area[68]. Reliability worth can then be evaluated in terms of the expected customer interruption cost by appropriately combining the CCDF with the calculated indices, i.e., expected energy not supplied, expected load loss, load point failure etc.

The Finnish Energy Market Authority uses the total cost concept including the customer interruption cost (CIC) as a cost of the DNO. An evaluation base has been produced by processing the results of the latest CIC research study in Finland[59] to define Sector Customer Damage Functions (SCDF) and a Composite Customer Damage Function (CCDF) for the whole country [60,61]. The latter is used in the CIC evaluation in the Finnish regulation model. Here we use the SCDF values (Table 4) to emphasize the differences in the customer mixes of the typical service areas. For these structural area types a CCDF is determined based on the customer mix in each area (Table 5). The regional differences observed in the research are not taken into account.

Table 4. *Sector customer damage function parameters for forced outages according to [59, 60] and [61].*

User group	EUR/kW	EUR/kW
Domestic	0,36	4,29
Agricultural	0,45	9,38
Industry	3,52	24,45
Public services	1,89	15,08
Commercial	2,65	29,89

Table 5. *Composite customer damage function parameters for structural area types.*

Type area	EUR/kW	EUR/kWh
Urban core	2,28	22,47
Urban	1,88	18,43
Suburban centre	2,28	22,47
Suburban AH	1,38	13,38
Suburban Mixed	0,92	9,34
Suburban Mixed EH	0,92	9,34
Suburban SH	0,66	7,32
Suburban SH EH	0,66	7,32
Industrial	2,90	23,46
Rural	0,59	7,84
Rural EH	0,59	7,84

▪ ***parameters: fault frequencies, repair times and switching times***

Fault frequency data is based on the Finnish interruption statistics 2006[69] collected by the Finnish Energy Industries. The latest statistics are based on the interruption data of 75 Finnish DNOs representing 82 % of the distribution volume in Finland. The statistical data is given in three categories depending on the network type: “rural”, “urban” and “city” with cable rate less than 30 %, at least 30 % but less than 75 % and at least 75 % respectively. A summary of the fault statistics is given in Appendix 8.

As the rural areas are divergent in terms of natural environment, we can not use average rural network performance statistics as such. There is a big difference between lines in forest and lines in open field or roadside (see Chapter 2). For this reason two rural MV feeder types with extreme fault frequencies and repair times have been introduced here.

To illustrate the expected performance of MV feeders, we can calculate reference or 'nominal' values for typical feeders in different environments. Three clearly distinct cases can be picked up: overhead lines in forests, overhead lines in open fields and fully looped cable feeders in cities. Table 6 shows the basic performance indices per feeder type.

Table 6*. Reference values for MV feeders in different environments (without switching).*

Feeder type	Fault frequency per unit length λ 1/100 km,a	Typical feeder length L km	Typical restoration time tr h	Customer interruption frequency $\lambda \cdot L$ 1/a	Customer minutes lost $\lambda \cdot L \cdot tr$ min/a
Rural, radial OHL, lines in forest	12	20	3	2,4	432
Rural, radial OHL, lines in open field	4	20	1,2	0,8	58
Urban, fully looped cable	0,6	5	10	0,03	18

The total unavailability time due to equipment failure can be divided into a 'locating time' to find the fault, a 'sectionalizing time' to isolate the fault and restore the supply partially or totally depending on each case and a 'repairing time' to repair the damaged equipment. In practice there are several phases and alternative procedures concerning fault location, isolation and restoration, and repair crew actions. Furthermore, the response times depend upon the point in time (hour, season) of occurrence. In order to illustrate how the system is operated in case of component failure, some simplified operating times must be defined: (1) Switching time t_{sw}: the time it takes the operator to find and isolate the fault, by use of disconnectors. Switching time depends on the operation of the disconnectors (manual, remote, automatic). (2) Repair time t_r: the time it takes to make the faulted component operational by repairing or replacing it. Typical action and response times are based on company data from Helsinki and Kainuu, and a research report [70].

Table 7*. Switching and repair times.*

	rural OHL in open field h	*rural OHL in forest h*	*urban cable h*
repair time (including the switching time)	1,2	3	10
switching time t_{SW1} for manual switching on site (including times for travel, locating and isolating the faulty section)	0,5	1	0,5
switching time t_{SW2} for remote and/or automatic switching	0,15	0,15	0,15

The switching times are quite similar in rural and urban environments. Although distances in rural areas are much longer, the number and location of repair crews are such that they compensate the differences in the distances. In urban environments the travelling times are lengthened by hold-ups due to traffic. The substantial difference is in repair times: OHL repair time is quite short due to direct access to the primary component while the repair time of cables is ten-fold. In practice, the last mentioned fact has led to the standard fully looped solution with cable disconnectors in RMU units enabling isolation of cable sections from the rest of the system.

5.3 Mitigation

System reliability can be improved by reducing the frequency of fault occurrence and by reducing the repair or restoration time by means of various design and maintenance strategies. SAIFI is improved by reducing the frequency of outages (by for example tree trimming and maintaining equipment). SAIFI is also improved by reducing the number of customers interrupted when outages do occur (for example, by adding reclosers and fuses). Strategies that reduce SAIFI improve SAIDI because if an outage does not happen, it does not add to duration. SAIDI is also improved by improving CAIDI through faster customer restoration. However, system improvements can make CAIDI go up or down, depending on whether the improvements have a greater effect on outage frequency (customer interruptions) or outage duration (customer minutes of interruptions).

To understand the various means of mitigation, the mechanism all the way from the cause of a fault to the end-customer equipment or process outage and the following restoration process all need to be understood[67]. Long interruptions are always due to component outages. Component outages are due to three different causes: (1) A fault occurs in the power system which leads to intervention by the power system protection. (2) A protection relay intervenes incorrectly, thus causing a component outage. (3) Operator action causes a component outage. These could also be scheduled or planned interruptions. Whether a component outage leads to an interruption depends upon what sort of redundancy the component in question has.

The basic categories of mitigation methods are: (1) reducing the number of faults (2) improving the fault-clearing process (3) changing the system design, so that faults result in less severe events at the equipment terminals or at the customer interface (4) connecting mitigation equipment between the sensitive equipment and the supply (5) improving the immunity of the end-customers' equipment. The first three categories are considered here.

Some examples of fault number reduction are:

- better shielding of the components and plant (using cables or covered wires instead of overhead lines with bare conductors, additional shielding wires or earth wires reducing the risk of lightning fault, placing equipment inside the buildings, fences, etc.)
- increasing the insulation level (insulation coordination) and related earthing practices
- increasing maintenance and inspection frequencies; preventive maintenance activities could have an impact on the frequency of faults by preventing the actual cause of failure
- optimal neutral earthing practice
- preventing maloperations by proper design of protection and control systems
- preventing human errors by designing easy-to-use systems (primary, secondary, control centres), training, etc.

Reliable and fast fault-clearing is part of system design by default. A special technique interlinking with the fault-clearing process is resonant earthing. It is applied to reduce earth-fault currents and hazard voltages to acceptable levels, and in OHL networks it has a preventive effect on interruptions by suppressing the fault arc. In cable networks this type of neutral treatment does not actually clear the fault but it makes it possible to operate most systems for long periods with a sustained fault until the fault can be cleared. Therefore it reduces the frequency of sustained customer interruptions.

The structure of the distribution system has a big influence on both the number and the duration of the interruptions and voltage sags experienced by the customer. When a power system component fails, it needs to be repaired or its function taken over by another component before the supply can be restored. The repair or replacement process can take several hours or, especially with power transformers and GIS-plants, even days up to weeks. At HV and MV levels in most cases the supply is not restored through repair or replacement but by switching from the faulted supply to a backup supply. The speed with which this takes place depends on the type of switching used. Many systems have interconnections which allow the transfer of some or all the load of a failed load point to other neighbouring load points through normally open points[66]. Reserve connections are a prerequisite for restoring the load downstream of the fault location by switching. If there are no reserve connections, only fault isolation and restoration of the upstream healthy part is possible. If there are reserve connections, downstream healthy parts can also be at least partially restored by switching and reconfiguring the network. A further system design task is to define the optimal number and location of switches and defining the level of automation (remote fault location, manual switching, remote switching or automatic switching) affecting the switching time.

There are several types of switches that can be used to connect or disconnect the feeder sections[71] : (1) Breakers equipped with relays, used to break short circuit currents and operating currents. Breakers can be remotely operated and have generally no limit in the number of times they can operate. Breakers enable the sections outside the affected area to operate normally. (2) Disconnectors, used to isolate faults are of two kinds; those that can be operated under load current and those that cannot. Disconnectors can not disconnect fault currents. (3) Fuses, used to protect certain equipment, have to be manually replaced or reset when triggered.

The service area of an MV feeder can be equipped with intermediate or lateral protection gear. In this case a fault downstream of the protective device causes no disconnection of the upstream load points. Although the number of faults is not reduced, the system interruption frequency index is improved since some faults are experienced by a reduced number of customers.

5.4 Evaluated cases

It is possible to evaluate such mitigation strategies which can be parameterized using the elements included in the network model. The impact of investments to reliability level and thus outage costs can be calculated accurately enough. The effect for instance of maintenance strategies is much more difficult to model and evaluate. In this study, the reliability level is studied in relation to certain investments into the network, but the maintenance strategies are not studied. It is assumed that the established practice represents the optimal situation accurately enough. The following basic system level options are studied at the MV feeder level:

- MV feeder system splitting using different types of switches (circuit breakers with protection function, manual disconnectors, remote operated disconnectors and automatic disconnectors for fault isolation and restoration) and with or without reserve connections between feeder segments and between substations; protection zones: time graded in parallel or in series (Figure 28)
- remote fault indicators
- shielding options: cables versus overhead lines in rural networks
- neutral earthing: impact of the possibility to operate MV networks in earth-fault conditions and thus prevent customer interruptions even in the case of a sustained fault

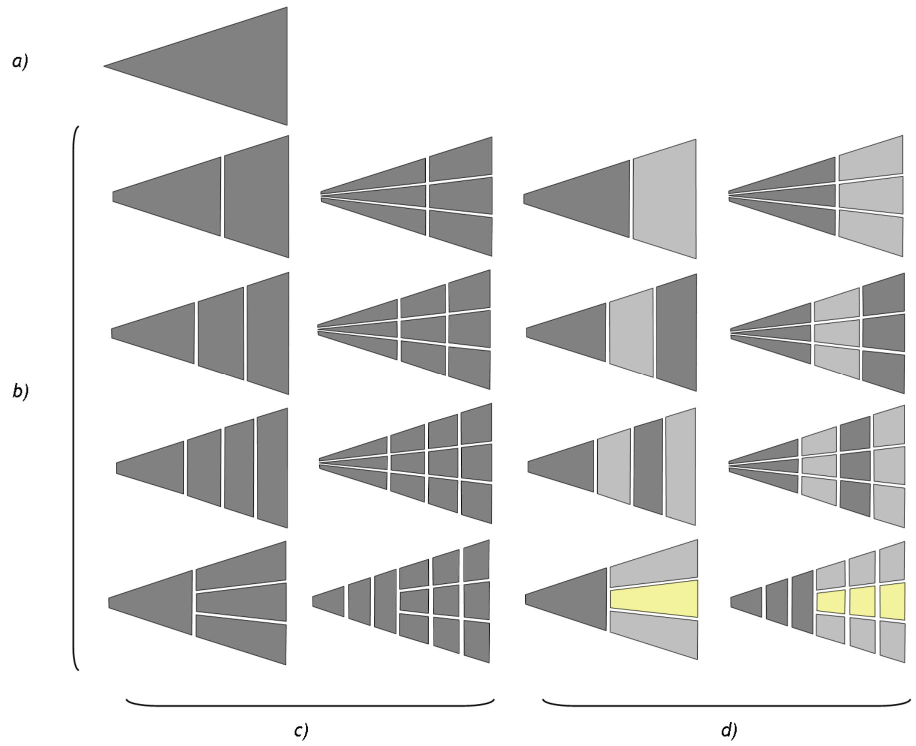


Figure 28. *Medium voltage feeder service area division into segments with switches for each segment to disconnect the segment from the rest of the system: a) a single section restored after the repair time b) multiple sections; the upstream healthy sections are restored after a switching time, the downstream healthy sections are restored after a switching time if reserve backfeed connections are available, otherwise they are restored after the repair time, the faulty section is restored after the repair time c) single protection zone; the whole feeder trips in the event of a fault d) multiple protection zones (depicted by different colours) created by intermediate circuit breakers, only the faulty zone trips.*

In urban cable networks the standard solution is to equip each RMU with cable disconnectors and thus the faulty cable section can be always isolated from the healthy network and each transformer station can be restored by network switching. The question then, is the switching time. In a basic situation, with no remote indication, the fault indicators have to be read in the field checking each transformer station in turn. If remote indication is applied, the repair crew can be directed straight to the right cable section and thus the switching time can be reduced (here assumed to be halved). Switching time can be further reduced by using remote and/or automatic switching.

In urban networks it is assumed that by installing earth-fault current compensation it would be possible to operate MV networks under sustained earth-faults and thus only short-circuit faults would cause customer interruptions. In that case, the customer interruption frequency could be halved (about half of all faults are earth-faults).

In rural environments the amount of load per lateral is such that it is not feasible to install a disconnector to each lateral. Long distances on the other hand make, for instance, remote controlled sectionalizers attractive. It is thus an optimization task to determine the number and type of switches along with the topology of interconnected feeder sections. Restoration time is depending also on the availability of reserve connections, i.e., an alternative supply route. In a purely radial network these are not available. The impact of building loop-forming lines is studied in combination with different kinds of switching.

A radical change would be to replace overhead lines with cables. This creates not only an economic challenge, but also technical issues such as compensation of the reactive effect of cables and the required amount of looping have to be solved. As a basic assumption, in rural environments the same fault frequency for cables is used as in urban environment. Earth-fault current compensation in connection with cables is assumed to be a standard solution.

Figure 29 summarizes the studied mitigation strategies.

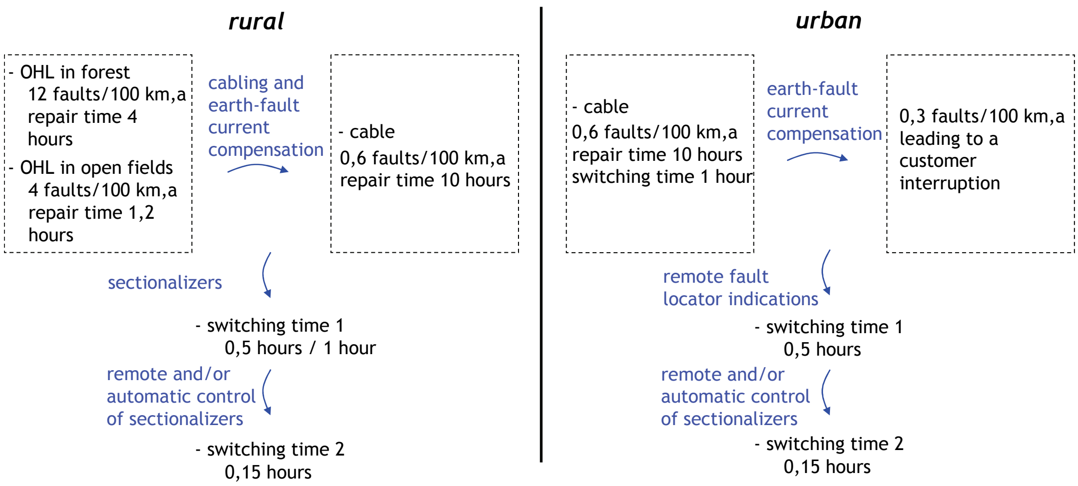


Figure 29*. Analyzed mitigation strategies in rural and urban networks. Mitigation actions causing additional costs are shown in colour (switching and repair times, see Table 7).*

5.5 Mitigation costs

Investment in reliability affects both capital and operating expenditures. These costs have to be weighted against the consequences of customer interruption costs and repair costs.

For manually and remotely operated disconnectors, network circuit breaker stations, and for the line costs, the EMA unit price list [58] is used. The operational costs for the switches are gathered from various utility sources (see Appendix 9).

In switching schemes, the additional costs for the system are not only switching, signalling and communication equipment. The feeders have to be dimensioned such that they can handle the extra load. The transfer capacity or reserve capacity affects the network cost in several ways: (1) the cost of extra line length and stations, (2) cost of higher rating of components, (3) lower losses in normal situations due to larger cross-sectional areas, (4) the added components are also liable to network faults and cause additional CIC. The effects of the points 2 and 3 partly cancel each other. In the evaluation, only the effect of extra line length fixed cost is considered.

The cost of neutral treatment is determined by comparing two equipment sets (arc-suppression coils and control equipment, neutral point transformers and MV circuit breaker bays) with different current rating in urban and rural substations. Since the capacitive earth fault current per kilometre of line is known for each line type, an average per kilometre earth-fault current compensation cost can be determined.

The cost data used in the reliability evaluation are summarized in Appendix 9.

6 REFERENCE NETWORKS

6.1 Reference substation supply areas

The main verification for the model network results is the reference given by the real networks in different environments. Substation service areas from Helsinki city and Kainuu in eastern Finland have been selected so that they would reflect the range of load densities in Finland. The substation area load density LD_{SA} range covered is 0,001 … 42 MW/km^2 (average value for the whole substation area) and energy density ED_{SA} range 0,003…231 GWh/kWh,a respectively. The intention was to choose service areas as homogeneous as possible to make a good reference. When smaller subareas of each substation are examined, it can be seen that particularly in rural environments the range of load density is quite large (Figure 30). In the energy density area 0,5…2 GWh/km2 (rural-suburban) it is quite impossible to find homogeneous-enough reference areas as wide as a substation service area.

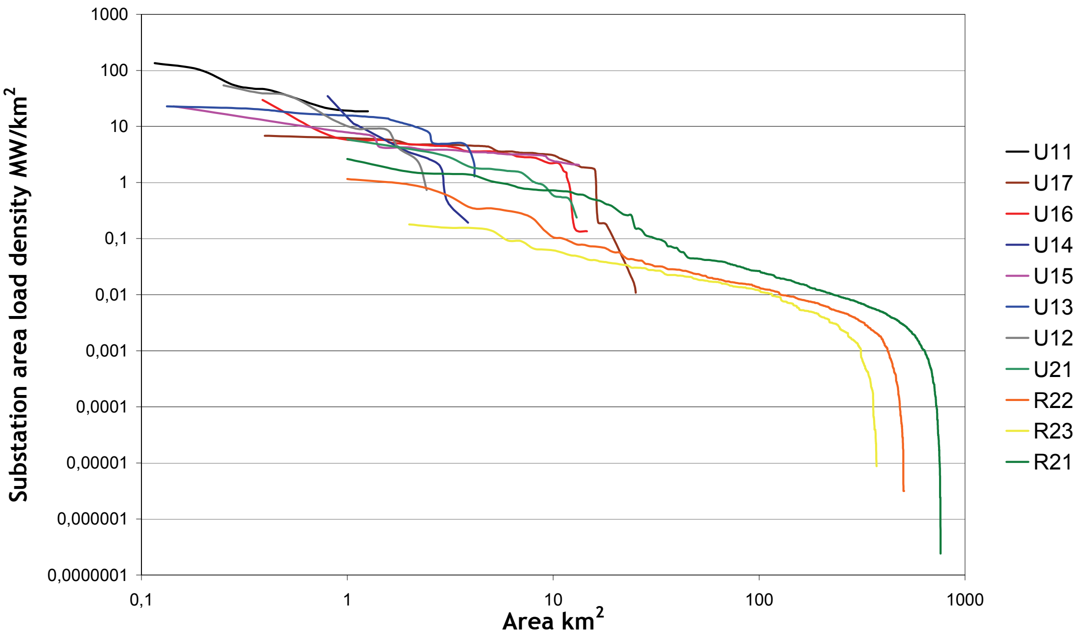


Figure 30. *Load density (MW/km^2) distributions of the subareas of the reference substation service territories (U11…U17 by 200 m x 200 m squares, U21 and R21…R23 by 1 km x 1 km squares)*

The network volume of the reference substation areas have been collected from network information systems. The same cost parameters have been used to evaluate the network value for both model networks and reference areas.

Detailed data from the reference substation areas is presented in Appendix 10.

6.2 110 kV meshed transmission system reference areas

The meshed 110 kV grid is modelled using three reference areas. Reference regions large enough are needed to ensure an adequate number of 110 kV loops and nodal substations. On the other hand, these areas should be as homogeneous as possible, a requirement hard to fulfil in a country the size of Finland. The chosen areas are the Helsinki metropolitan area, the south-eastern area with predominant industrial regions and the eastern area which is mostly rural. Each area represents roughly a volume of 1000 MW of distribution network load[72] and they are also very similar in size measured by population and the number of distribution network customers. The geographical areas and load densities on the other hand are quite different.

For each reference area, the line length of the 110 kV meshed system and the number of nodal substations has been explored. Based on these, the network repurchase value and its annuity has been determined. The reference network unit cost is given by the annuity divided by the annual energy delivered to the distribution network customers within the respective area.

The reference area data are summarized in Appendix 11.

6.3 MV feeder system optimization algorithm ("VOH")

Based on real connection point data from some reference substation areas, reference MV feeder systems have been created using an optimization algorithm (called "VOH" after the Finnish acronym for the project) developed at Helsinki University of Technology, Department of Electrical Engineering. The main idea is to compare the general reference network created using the geometrical and symmetrical model with a software-optimized reference network. An additional aspect is the comparison of two MV voltage levels, the historical 10 kV still in use at the city core of Helsinki and 20 kV, which is the industry standard today.

The developed optimizing algorithm produces a close to optimal network or series of interconnected networks quickly and can deal with real-sized networks. The main principle is to use a highly efficient algorithm to produce a candidate network via a series of improving feedback loops, which is then further improved by a series of branch exchanges.

A more extensive description of the algorithm is presented in the beginning of Appendix 12.

7 RESULTS AND DISCUSSION

7.1 General

As the outcome of the model network evaluation procedure (described in Section 4.4), optimal substation densities and corresponding network volumes are obtained for the given range of HV/MV substation energy density ED_{SA} and the modelled area types. Before going into the cost analysis, a brief look at the station densities is taken (Section 7.2), because they reflect the physical constraints on the network design. The dissection of the total cost includes the cost level analysis (7.3) and the cost structure analysis (7.4 to 7.6). The computed model network results are compared with the correponding data from actual substation service areas presented in Sections 6.1. and 6.2, and in Appendices 10 and 11 .

Reliability indices are determined for the model network sample feeders with different mitigation strategies as described in Sections 5.4 and 5.5, and in Appendices 8 and 9. The results are compared with the performance of the Finnish DNOs (7.7).

The medium voltage network geometric models are compared with software-optimized reference networks based on the connection point data of the reference substation areas (7.8). The optimization algorithm is described in Section 6.3. and in Appendix 12. This MV feeder system optimization algorithm is used also to compare two MV voltage levels, 10 kV and 20 kV.

Finally, the validity of the results is discussed and some model improvements and supplements are suggested (7.9).

7.2 Connection point and station densities

The low voltage connection point density is generic, based on the total energy density, the share of open space and the customer mix in each area. In the very sparsely loaded areas the transformer station density coincides with the low voltage connection point density, meaning that each connection point requires its own transformer (Figure 31). At the lowest and mid area load densities voltage drop and protection limits determine the operating ranges. At high load densities (> ca. 1-2 GWh/km^2) on the other hand, station densities are capacity restrained and the distance between stations decreases while load density increases. An empirical maximum distance between EHV stations of ca. 200 km is set as a constraint. Eventually, the station densities are determined almost entirely by the technical restraints. This actually means that for a system designer the most important task is to determine the optimal set of voltage levels. For an existing system these are given parameters, at least where short and medium term planning is concerned.

As can be seen from the respective transformer station and HV/MV substation maximum loadings, the turning point set by the capacity constraint is well observed (Figure 32). The resulting transformer ratings are higher than these values in urban areas where some capacity has been reserved for faults in neighbouring stations. If only single contingencies and the cost minimum were considered, much higher station capacities would result. These high capacities would at the same time lead to a high risk of common mode faults and an impractical number of feeders per station. Relating to MV/LV transformer stations, the maximum rating of 1 MVA is given by the safety standard, which takes the fire hazards into consideration. In urban core areas a common solution is a ‘double station’, with two identical transformer stations at the same location in separated rooms but still utilizing common construction elements. Thus it would be possible to benefit still more from the economies of scale. Concerning HV/MV substations, there is a low but still distinct possibility of losing the whole station residing in common premises. The MV feeder system easily becomes a bottleneck, especially in the case of only a few neighbouring substations backing each other up (a quite usual geographical circumstance).

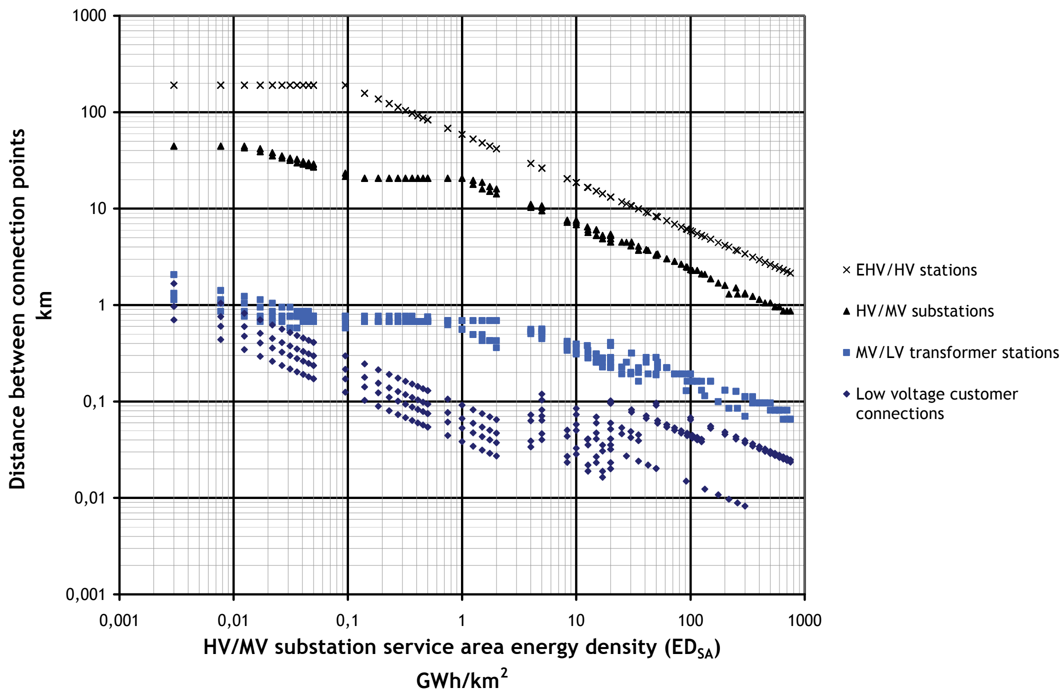


Figure 31. Distances between substations and low voltage connection points.

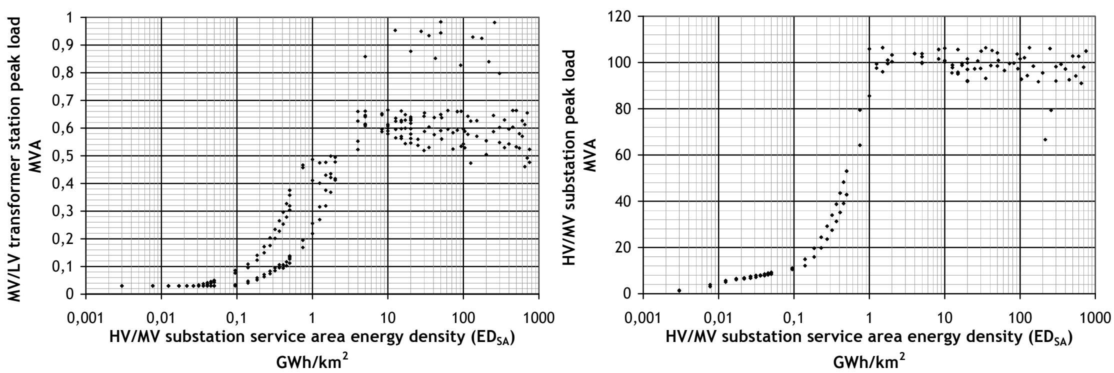


Figure 32. Substation maximum loads.

7.3 The cost level

Figure 33, being one of the key results of this study, shows the reference cost levels (c/kWh) for the model networks of different area types. The respective reference points from actual substations are also included in the figure. Conclusions regarding the effects of load dispersion (the share of open space) and customer mix can be made in addition to a general depiction of the effect of energy density.

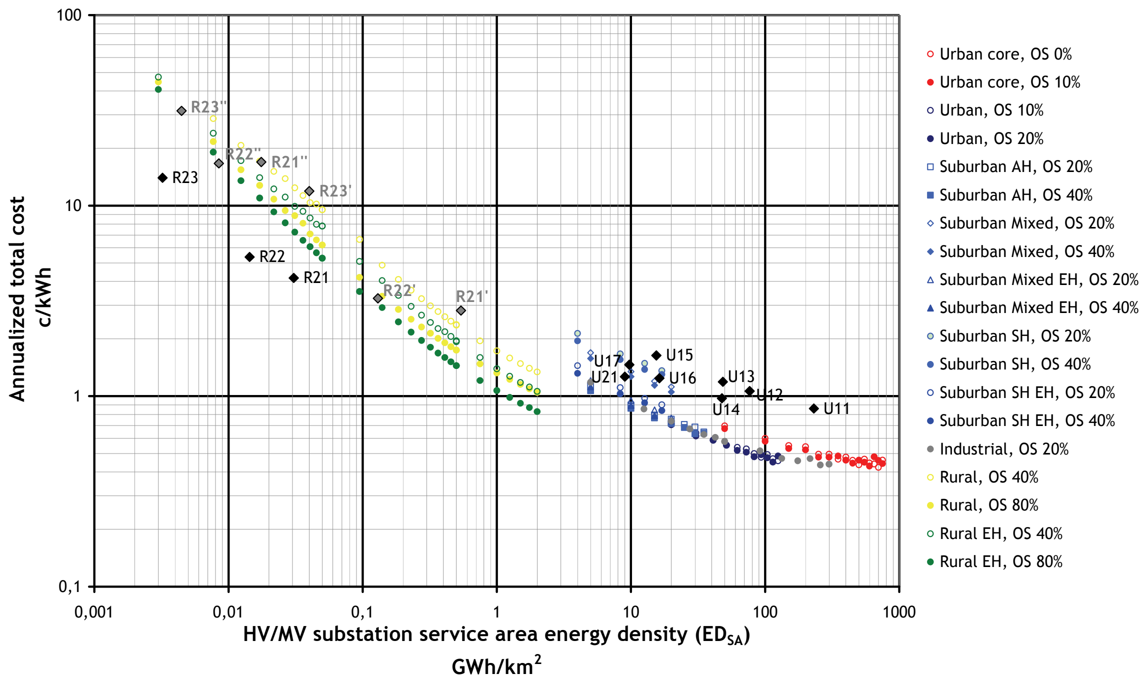


***Figure 33**. The annualized total cost versus energy density.*

The concentration of loads is a significant cost factor, particularly in rural areas where the share of open space can be as high as 90 %. The larger the share of open space, the more the load is concentrated, and the lower the cost. In urban areas the share of open space is restricted to a few tens of percent and the effect is relatively small in total cost.

The effect of electrical heating load is of importance in rural areas; when the basic network infrastructure built for other electrical loads is utilized in transferring the energy needed for heating, the greater amount of energy transferred will lead to a lower per kWh cost.

The transition zone from rural to suburban including suburban areas is sensitive to choices of equipment structural types due to the immense low voltage network volume. In these environments they have a global significance, i.e., they have the most powerful effect (line length x cost-rise effect). The customer properties also have a remarkable effect on cost. The concentration of household loads in the case of apartment blocks will lead to considerably lower unit cost compared to small house areas with similar electrical load (no electrical heating). The electrical heating loads have the same impact on unit cost as in rural areas.

When moving towards the highest load densities in urban and urban core areas, the cost lowering is attenuated due to the higher unit cost of equipment. The attenuation is easily observed in Figure 34 where the total life cycle cost is presented per customer connection. This figure also shows the effect of 'lumped' customer structure (many customers per connection) in urban areas where the cost per customer and the cost per connection point differ substantially from each other. The relative cost-rises are analyzed more closely in Section 7.6.

For the rural reference substations R21…R23 the most appropriate network model reference is 'Rural EH OS=80%'. All reference points fall well below the model network result (note the logarithmic scale!). The rural zone model is based on homogeneous load dispersion. However, at a closer look, the reference substation areas are quite heterogeneous (in terms of load distribution). The urban areas with systematic land use zoning seem to be much more homogeneous. In the rural area analysis it can be observed that the majority of the load is concentrated in quite a small area while the other squares with electrical load are very sparsely loaded. Therefore, it seems obvious that the rural network model, now scattering identically loaded areas symmetrically around the service area, needs to be accommodated to more heterogeneous substation service areas. To test this idea, a trial was made to divide these reference substation areas in two subareas: one subarea covered 90% of the total load and the other subarea 10%, respectively, as in Figure 35 (actually there is also a third subarea: the one with no load, i.e., open space). In this manner, two more homogeneous subareas were created.

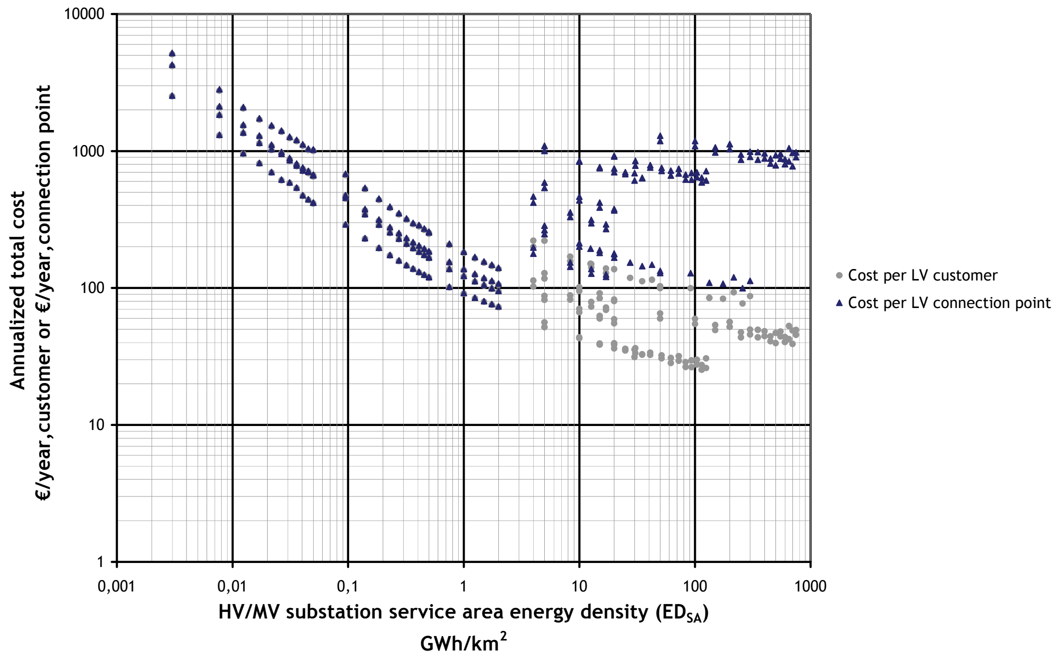


Figure 34. *Cost per customer and per connection point.*

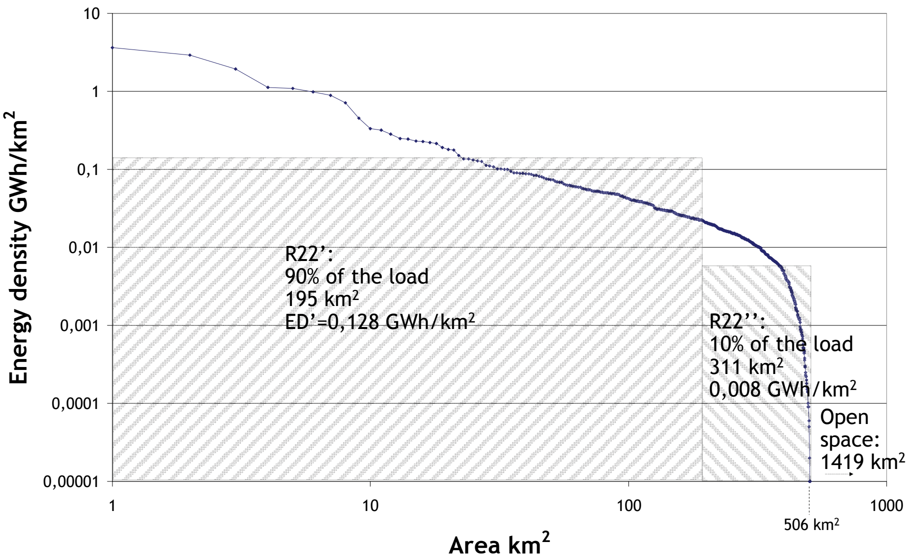


Figure 35. *The load distribution of the rural reference substation R22 service area (by 1 km x 1 km squares), and its division into two new subareas R22' and R22''*

The subareas with the higher load density contain 60-76% of the network volume. A network density indicator (km/km^2 as a function of energy density) given by the network model is used in the estimation of network volume. Therefore, the cost level in this area would be (0,6…0,75)/0,9 times the original average cost level for the whole area (meaning the cost is lower since the above factor is <1). The subareas with lower load density contain 25-40% of the total network volume and the respective cost level correction factor is (0,25…0,4)/0,1 (meaning that the cost is higher since the factor is >1). The adjusted reference substation area points designated R21', R21", R22', R22", R23' and R23" should settle themselves above the model network results in Figure 33 because for these new subareas OS≈0%. Considering the indicative nature of this test, the result supports the idea of rural network model fragmentation.

The following conclusions can be made: (1) the network service area must be divided into subareas homogeneous enough to be able to use the model network approach for the cost level estimation of these particular areas (2) the heterogeneous service areas of DNOs can be evaluated to some extent by division into smaller subareas, knowing the energy density values of these subareas but only the total cost and network volume (3) it is beneficial for a DNO operating in rural areas to have at least a moderate size urban area within its service territory to compensate the extremely high cost in the most sparsely loaded areas.

Concerning the urban reference substation areas it must be noticed that the areas U11…U13 in urban and urban core areas are 10 kV substations while the model network calculation has been carried out only using 20 kV voltage. Therefore the cost level is higher for these reference points. The effect of using 10 kV voltage compared to 20 kV is discussed later in Section 7.8. The suburban reference substation points are quite well fitted to the model network results in the overall picture. In a more detailed cost level analysis in suburban and urban areas, heterogeneous customer structure is a major concern. Modelling typical customer mixes that would depict the characteristics of the whole substation area may be very difficult. These may have to be determined case by case.

7.4 The cost shares of different network levels

Figure 36 shows a clear pattern of cost relations in different environments. In sparsely populated areas the MV feeder system is dominant. The share of low voltage network level is highest in the suburban areas with a high share of small houses, i.e., a high number of small load points each requiring its own cable connection. At highest load densities the relative share of nodal points (substations) is increasing while the line length per connection point is decreasing.

The reference substation areas show similar cost relations with two exceptions. (1) Particularly in the lower load density end the HV system cost is unrealistically high (which is another reason why the rural network model gives too high costs). In reality there are not so vast areas with such low load densities to be fed by meshed EHV and HV systems. The same applies to some degree to the other extreme, i.e., the highest load densities in urban core areas. At this end, however, it is quite possible that a metropolitan city core requires its own EHV station(s). The HV system cost shares of the reference substations reflect more the reality. (2) In urban environments the cost share of MV/LV transformer stations is lower in the reference areas. One explanation could be that it is customary to use so-called double stations in urban and urban core areas. Double stations, which result in better utilization of construction elements and thus lead to lower cost per kWh, are not included in the network model used in this study.

With the reservations relating to the above mentioned discrepancies (which to a large extent could be amended in the model) the network model generates network components in the right proportions compared to each other. This is an important observation because it opens the possibility to use the model network approach in relative comparisons.

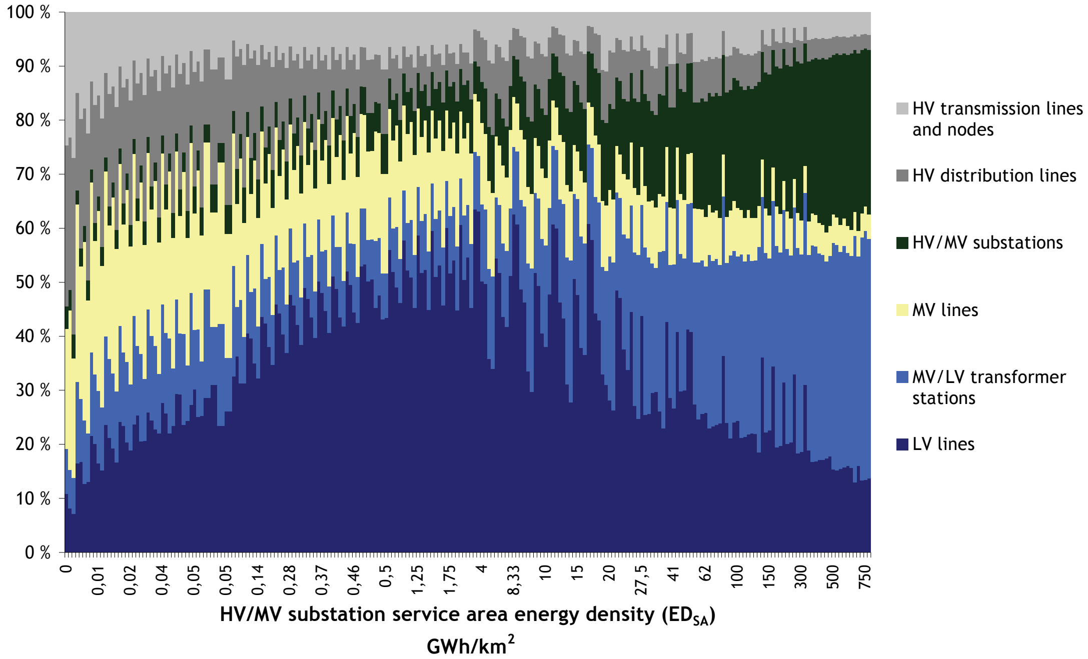


Figure 36. *Cost relations between different network levels: the model network areas.*

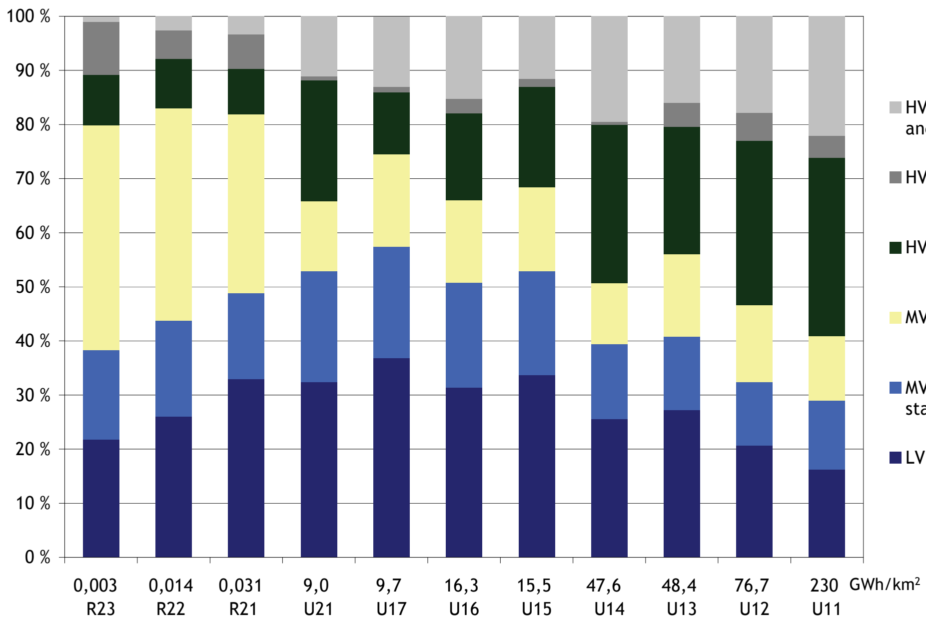


Figure 37. *Cost relations between different network levels: the reference substation areas.*

7.5 The cost versus total line length

Sometimes the total network cost is estimated using a specific cost per total line length. The generally recognized differences in unit costs of lines (Appendix 4) in different environments are a good starting point in this estimation (Figure 38). The fixed part reflecting the cost of HV and MV nodes can be roughly estimated by the cost of an HV/MV substation and the cost of an MV/LV transformer station multiplied by the number of stations. Particularly in urban environments the relative importance of this fixed cost is high and cannot be underestimated. The same phenomenon was already clearly shown in Figure 36 and Figure 37.

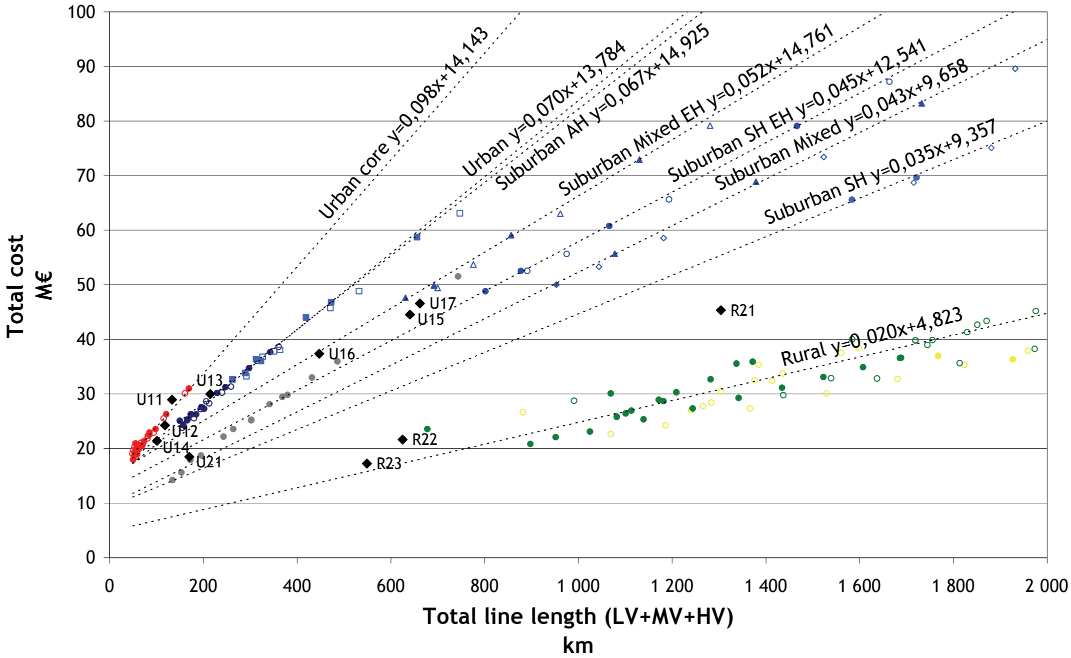


Figure 38. *The total life cycle cost versus total line length.*

7.6 Cost depending on the structural conditions

In Figure 39 and Figure 40 the total cost is segregated into the basic cost of electrical equipment and the cost elements related to the construction environment. Due to external conditions, in densely built areas shielded structures (insulated cables instead of bare conductors, enclosed switchgear instead of open air switchgear) have to be used. The additional cost due to these is presented by the dark blue bar in Figure 39. Additionally, somewhat more has to be invested in construction elements (buildings, concrete troughs, etc.). In rural networks the share of the construction elements is also high due to the cost of poles, which are categorized in this group of costs because they correspond to the trenching cost of cable lines.

The division between the cost components may be somewhat coarse and even artificial, but it still shows that in an urban environment a significant portion of the infrastructure cost is other than the cost of electrical equipment and their operation. Trenching, concrete troughs and buildings form a greater portion of the total cost. Route length extension amplifies the effect of construction cost elements. Since in urban environments there are several builders of infrastructure, collaboration between the actors is crucial from the point of view of costs. Cooperation has to be ensured already at the planning stage, which makes the task of planning toilsome.

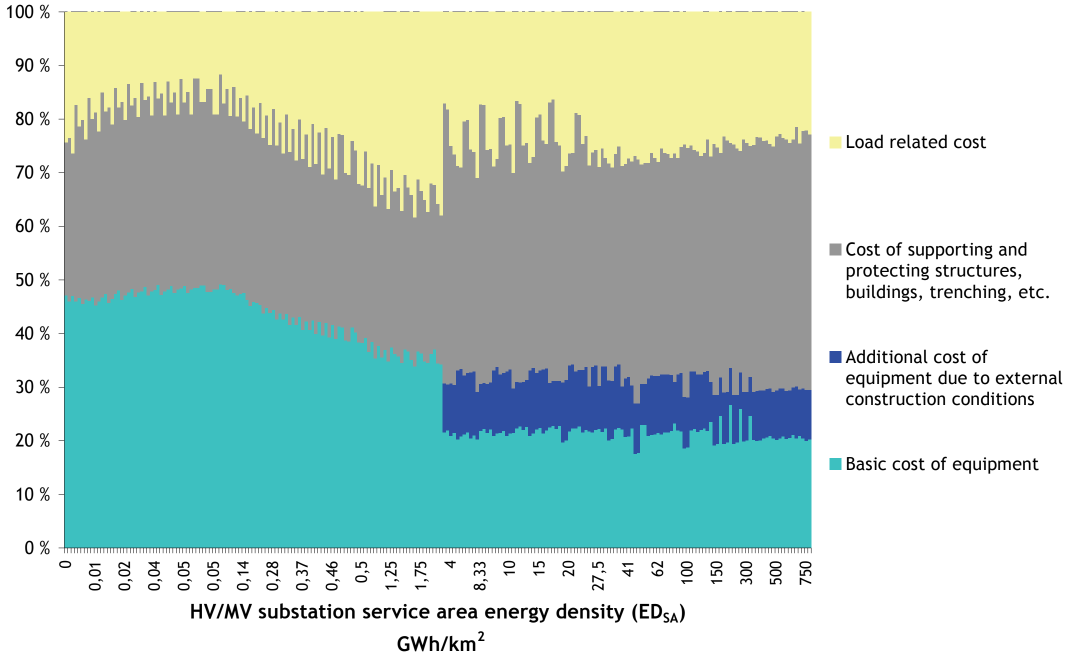


Figure 39. *The total network cost divided into the basic equipment cost and the cost elements related to the construction environment: model network areas.*

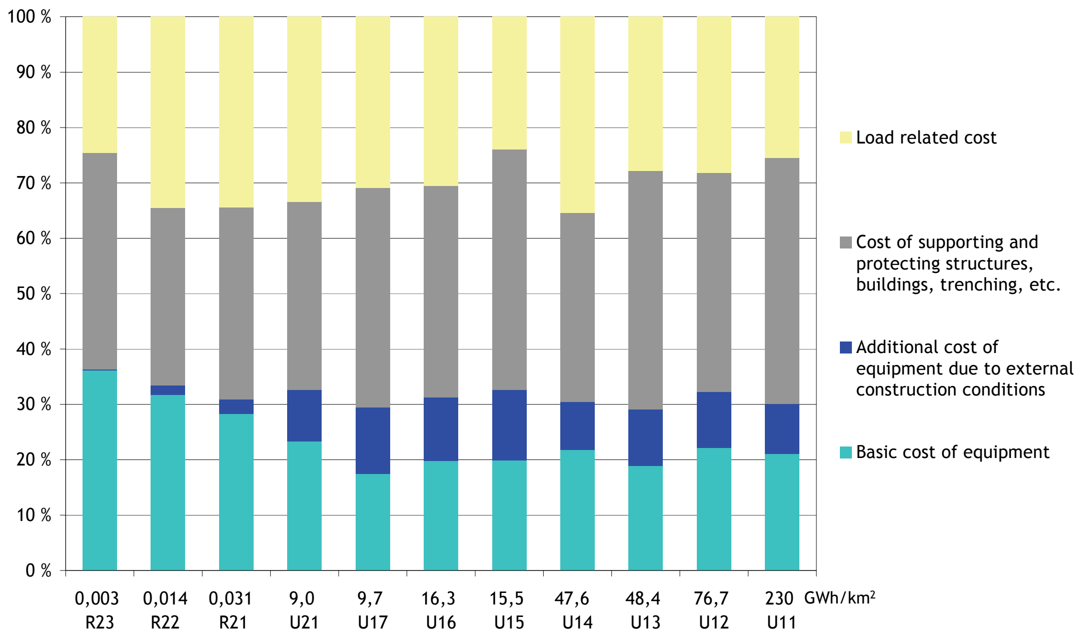


Figure 40. *The total network cost divided into the basic equipment cost and the cost elements related to the construction environment: reference substation areas.*

The fixed cost (not dependent on load) is in the range 65…85% of the total cost and the rest is load related. As the portion of losses is less than 10% [57], the other load related costs, i.e., the cost of equipment ratings higher than the minimum, should cover the rest.

For each area type, the total network cost is compared to the minimum cost network (see Chapter 1, Introduction) to fulfil the basic supply task. The cost-rises proportional to these minimal costs are presented in Figure 41.

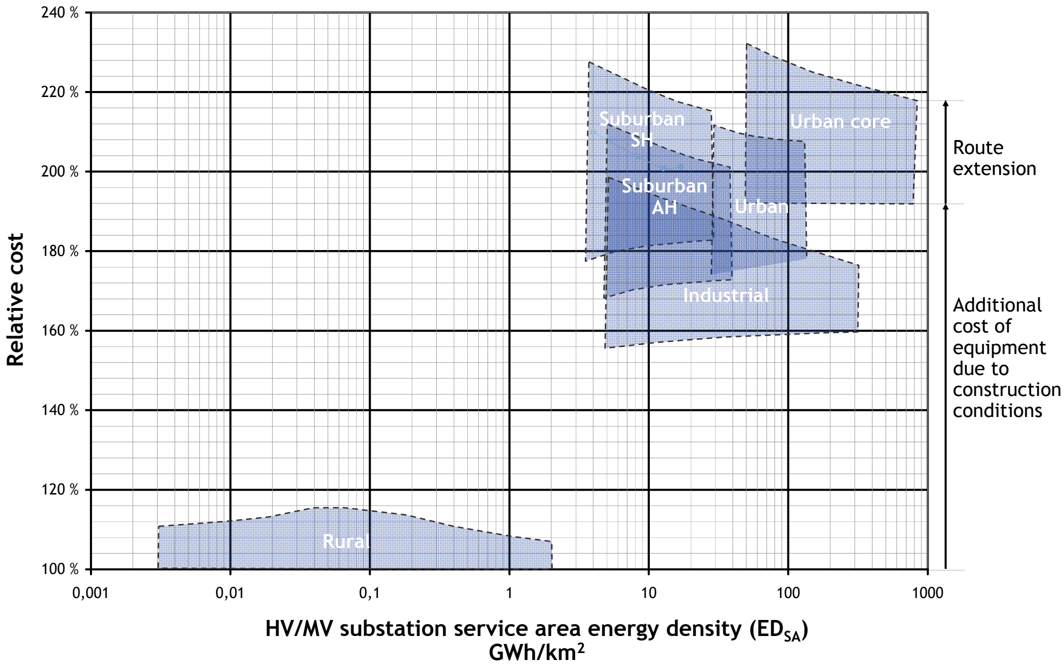


Figure 41. Cost-rises proportional to the minimal network cost.

The cost-rise due to two causes is presented: the additional cost of equipment due to construction conditions and route length extension due to topography. As expected, in urban areas the factors limiting the free use of land and the consequences of that are most significant. They affect the network cost through extended line lengths and restrictions on using certain types of equipment. The significance of the equipment requirement is shown by comparing industrial areas with other urban areas: in industrial areas the requirements (for aesthetics for instance) are not assumed to be so high.

The effect of customer mix can be seen in a comparison of suburban small house and apartment block areas. In urban small house areas both the urban equipment requirements (cables) and line length extension (use of street grid) effects are accumulated: there a large number of small load points have to be supplied using individual feeders.

7.7 Reliability enhancement strategies (case studies)

▪ ***rural networks***

As explained in Chapter 5, a set of mitigation actions can be employed to reduce fault frequency, customer interruption frequency and the customer minutes lost. Figure 42 presents the effects of these reliability improvement strategies for a sample rural feeder. In typical rural areas the most economic action is to install sectionalizers, in some cases remote controlled. In a few cases it is feasible to split the feeder into several protective zones using intermediate circuit breakers.

Using additional reserve connections, the customer minutes lost can be further reduced a significant amount, but the total cost in most environments is usually not lowered in open field environments with lower fault frequency and faster repair time. In the case of lines in forest the situation is understandably different. There most mitigation actions are profitable from the customer's point of view.

When lines are renewed, e.g., because of aging, there are two alternatives to replace the existing overhead line: either (1) build the line with a new routing along roadsides where the vulnerability to faults is significantly lower and the repair time is shorter or (2) replace the line with an underground cable. The first strategy seems to be profitable in all cases as long as the line length remains about the same.

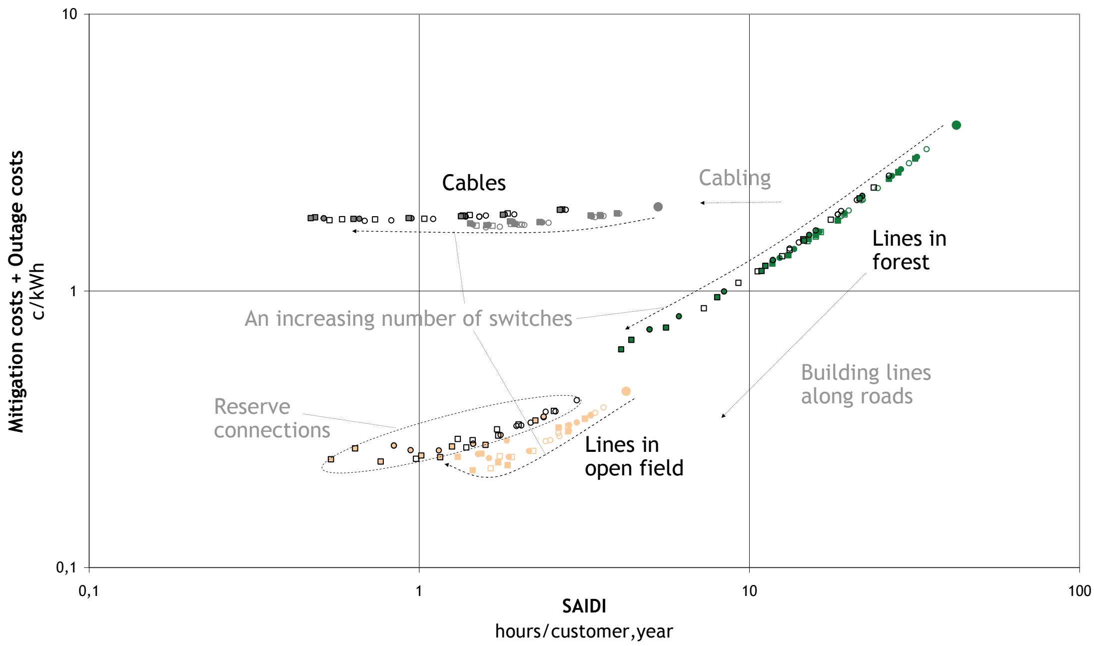


***Figure 42**. The effects of reliability improvement strategies for a rural feeder (ED_{SA}=0,014 GWh/km^2).*

Cabling is not feasible in most areas (at least not with the cable cost level used in this thesis). In rural environments the same fault frequency for cables is used as in urban environments. Probably the frequency of external faults (digging) is not so high in a rural environment, but on the other hand climatic causes (overvoltages) may increase the fault frequency. As there is no knowledge of this, the same fault frequency has been applied.

Concerning cables it has to be noted that to reach similar fault duration (as measured by the CAIDI index) as in OHL networks, a high number of switches are needed to isolate faulty cable sections with long interruption times (repair time).

Comparing rural lines in different load density areas (see Appendix 13) it can be seen that in the most sparsely loaded areas there seem to be less means of mitigation that are feasible. This is due to the low amount of load, which means that the amount of CIC is low compared to the mitigation costs of long feeders. On the other hand, in higher load density areas (particularly if lines are in open field conditions) the situation is the same, but now the reason is the initially low fault frequency and relatively short repair time. In the mid-area the situation is much as is described above in the case of the sample feeder.

▪ ***urban networks***

In a fully looped system with standard equipped RMUs the effect of remotely controlled sectionalizers can be deduced mathematically. The improvement depends upon the number of segments sectionalized using N_{SW} remote controlled switches: interruption duration is the switching time t_{SW1} for $N_{SW}/(N_{SW}+1)$ segments and switching time t_{SW2} for $1/(N_{SW}+1)$ segments while the total number of segments is $N_{SW}+1$.

It seems that money spent on a few sectionalizers (with remote fault indication assumed) is more profitable than investing just on faster fault location using remote fault indicators (Figure 43). This actually means that the step from a unidirectional surveillance system of transformer stations to a bidirectional system (including controls) is not big.

The most cost-effective mitigation measure, however, is earth-fault current compensation. In urban environments with so-called global earthing systems it is possible to continue operation under earth-fault conditions and thus prevent customer interruptions.

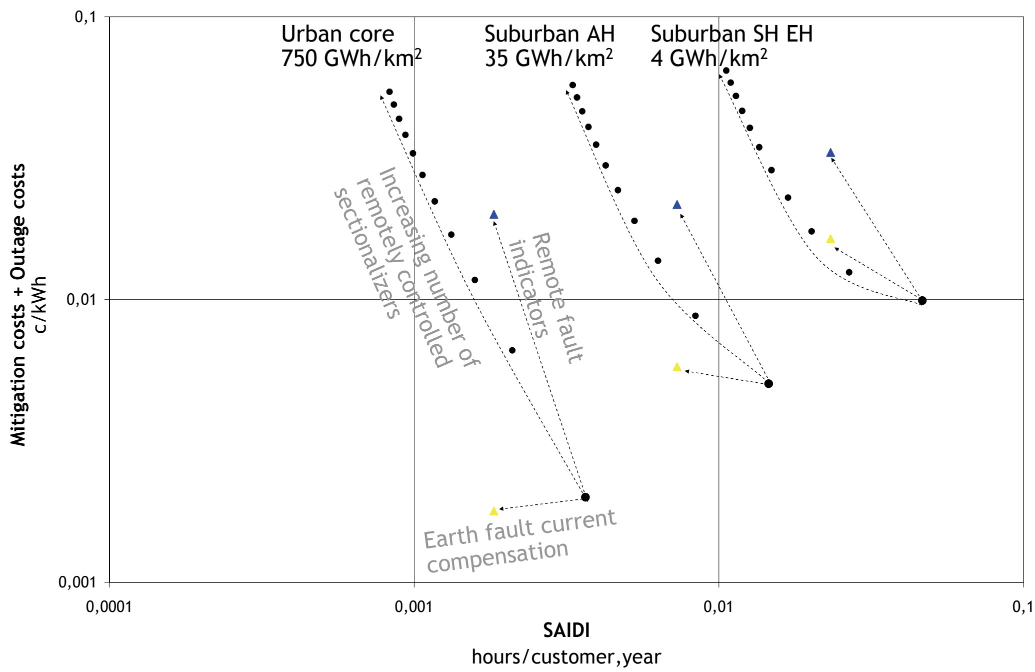


Figure 43*. The effects of reliability improvement strategies for urban feeders.*

Urban feeders in different types of area show similar patterns of performance improvement and cost effects (Figure 43). Partially this is due to using an average cable fault frequency for all type areas. In reality the fault frequency is higher in suburban areas with, e.g., higher construction work activity. Therefore, in suburban areas the mitigation measures would actually be more profitable.

▪ ***summary of reliability evaluation***

The purpose of these case studies was not to explore thoroughly the possible mitigation strategies but to test the model network approach in evaluating and estimating the reliability indices. Only the MV feeder system is included in this study but it still defines the basic reliability level of a distribution network.

Appendix 13 summarizes the calculations that were carried out. Sample feeder performance indices (SAIDI, SAIFI, CAIDI) from both urban and rural environments are presented. A set of sample feeder results is compiled in one figure, which gives an overview of the performance of feeders in different environments (Appendix 13, part 4).

If we compare the results with the data gathered by the Finnish Energy Market Authority [57] (see also Chapter 3) we see how the CIC values of the Finnish network operators fit into the ranges calculated using sample feeders (Figure 44). The CIC values include all sudden interruptions, i.e., substation and transformer station faults are also included. On the other hand, the model network cost part is comprised of not only CIC but also the mitigation costs. In the urban environment the relative portion of transformer station and substation faults may be greater than that of line faults. Therefore, the urban DNOs' SAIDI values do not fall into the sample feeder performance range. This is once again due to the relative share of nodal points in the network volume compared to the length of lines, and the result is analogous to the cost analysis in Section 7.4.

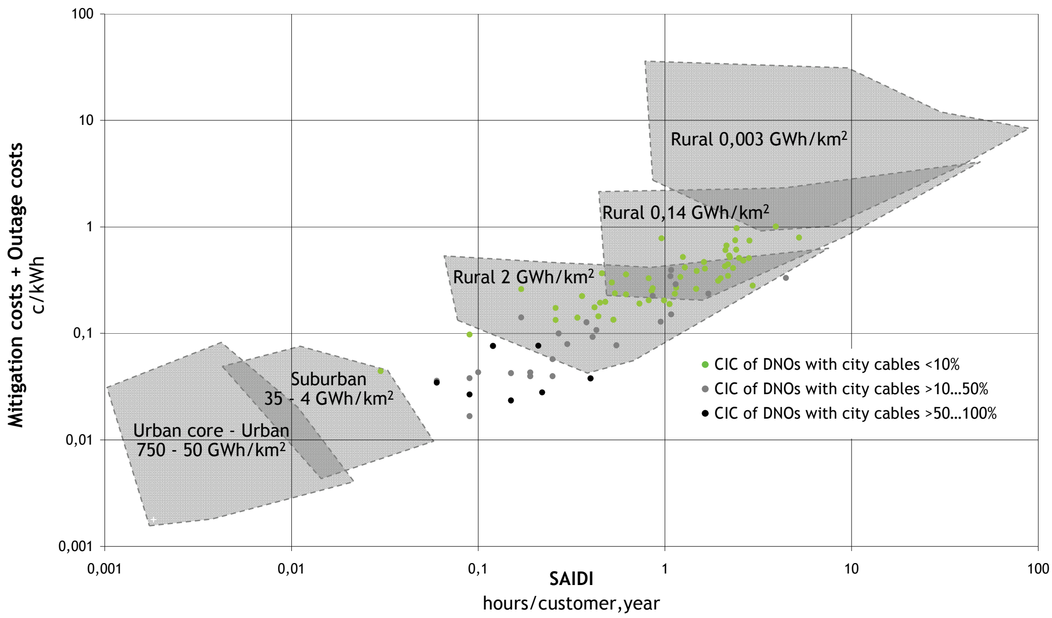


Figure 44*. Comparison of model network (sample feeder) SAIDI values and the CIC values of the Finnish DNOs [57] segregated by the amount of cable lines in the city environment.*

Here we must also remember that the network operator's service territory usually contains feeders in divergent environments. Therefore, in evaluation a weighted sum of different homogeneous feeder type models has to be used to calculate the overall performance of a DNO.

These coarse case studies and a comparison to DNO data show that distribution system (average) performance can be estimated using a model network approach. The model can quite easily be fitted to reflect the essential characteristics (vulnerability to faults, repair and switching times, network splitting using switches) of a particular network solution and external conditions. The model networks themselves are an input here as they produce the network volume (e.g., line length, number of stations), which functions as a 'fault antenna' and defines the number of faults to be expected.

7.8 MV feeder system optimization algorithm ("VOH")

Using the optimization algorithm for MV networks, three viewpoints were examined: (1) comparison of the output of the geometric network model using homogeneous transformer station (TS) density and the optimization algorithm using the actual locations of TSs, (2) comparison between the actual networks and the optimized networks, and (3) comparison of 10 kV and 20 kV feeder systems.

The optimization algorithm was applied to four urban substations, three of which are 10 kV substations. The algorithm was run for both 10 kV and 20 kV voltage levels. Two alternatives were optimized, one with forced full-looping and the other with an optimized degree of looping. In the latter, alternative satellite branches are also allowed in the urban cable networks. The results are presented in Appendix 12.

In the comparison, some adjustments have been made to take into account features in the actual networks that are not included in the network model. These are (i) the direct reserve connections (without any load) between substations which are needed in the case of a perimeter substation, especially when the MV voltage is 10 kV, (ii) the MV customers whose connection point is in the HV/MV substation bay but whose feeder cables are nevertheless modelled in the network information system, (iii) the actual LLAF which may be higher than the assumed $\sqrt{2}$ in the model, (iv) the vertical cable length that was not accounted in the LLAFs measured from two-dimensional maps; this has in fact a quite significant impact on the cable length when the TS density is high, (v) the adjustment of the substation service area so that the number of transformer stations is the same.

The following conclusion can be made from the comparisons:

(1) The geometric model and the optimization algorithm give almost identical cable lengths. This means that the geometric model based on evenly distributed TSs can be used in the estimation of network volume, at least in more or less homogeneous urban areas.

(2) If we use the length of the optimized fully looped network as a baseline for the comparison, the reference values are (see Appendix 12)

• fully optimized network (branches allowed)	network volume:	~ 90 %
• optimized fully looped network	"	100 %
• actual network	"	~ 130 %

So, there is a theoretical saving potential of 25-30% in the actual networks. This potential is, however, only exploitable if the network is renewed. Therefore, the replacement strategy of an aging MV cable network and transformer stations is of great importance. The looping ratio of a fully optimized network is 72-83% according to the results. This gives a network planner a challenge, in deciding whether full looping is required for each TS or not.

(3) The line lengths of 10 kV networks are 30-40% higher than those of 20 kV networks even in an optimized solution. In the real world 10 kV voltage is even more problematic because it is used in the city core areas where the number of large MV customers is high. The allocation of TSs to the feeder loops is difficult in such a way that the capacity of the cables would become fully utilized. The difference between 10 kV and 20 kV is remarkable, and should be taken into account in network comparisons. The reference substation area values, for instance in Figure 33, must be interpreted with this knowledge.

In summary, it can be claimed that a simple geometric model based on the average distance between TSs is suitable for the estimation of MV line length in relative comparative studies as far as urban areas are concerned (only urban networks have been reviewed in this respect). In absolute comparisons between model networks and actual networks, care is needed when interpreting the results. Local conditions, especially different voltage levels, have to be taken into account.

7.9 Discussion

▪ ***validity of the results***

The principle validation of the results has been embedded in the treatment of the results in Sections 7.2-7.8, utilizing the actual substation area data and the optimization algorithm output as references.

The basic building blocks of the evaluation process were presented in Figure 2. The supply task is described by modelling load dispersion and the construction conditions. One can argue whether these models reflect the real supply tasks, but on the other hand, neither the customer mixes nor external constraints are fixed. New descriptions can be generated whenever necessary. The results in this study are valid for the chosen descriptions, which were based on load analysis at the national level and spatial analysis of actual service territories in the Finnish metropolitan area. One has to also take into account that these descriptions are not constant over time, but may change, at least in the long perspective.

The geometric analytic network model based on connection point density is perhaps the most likely cause of errors. It was discussed in Section 7.2 that the transformer station and substation operating ranges were determined almost purely by the electrical boundary conditions. In an approximate model like this there will only be very coarse control of these constraints which should lead to feasible ranges of operating radius and transformer capacity per station. Particularly in an urban environment, the capacity constraint, defined by the permitted amount of risk and the reserve power required, determines the substation size and thereafter the shared infrastructure cost of the feeder system and its load points. Thereby it has a direct impact on the economies of load density. Modelling the technical constraints may be one of the key issues in the further development of the model network approach.

The unit costs of components and structures are based for the most part on statistical data used by the regulator. The problem is the more exotic installations in the urban environment where we have to rely on a more restricted cost base. The operating and maintenance costs per component are not well documented and thus not well modelled. They are based on general estimations ('a few percent of the investment per year') and some sparse documented data from DNOs. However, the portion of (direct) O&M costs is still a fraction of the total cost and the accuracy not so crucial.

The linear approximation of costs leads to underestimation of cost. Normally, not all cable cross-sections and substation combinations are usable, and the underestimation is still greater. Division of the cost to a fixed part and load dependent part is manually adjusted since standard curve fitting tools would sometimes have led to too low a fixed cost, which had to be avoided. It is important that the relations of the fixed cost portions reflect reality as well as possible since the cost differences in different environments spring from here. After manipulation of fixed costs, there might be some distortion between the fixed cost and the variable (load dependent) cost. The linear approximations were generated for typical utilization times per network level. In a more accurate process they should be determined following the actually used customer mix and the respective load profile.

Other studies that would be commensurable in the sense of comprising several voltage levels are not available. The assurance that the resulting reference cost levels in different environments are reasonable can be checked by comparing Figure 12 and Figure 33 (remembering that the direct network cost is around 60% of the total cost in Figure 12).

During the whole process there was an intentional effort to make the model as simple and robust as possible. Despite all the simplifications it seems that at least the framework is qualified for further development. Some ideas for developing the model are discussed in the following.

▪ ***needs for model improvements and supplements***

A static single-period model was chosen to fit the purpose of building a comprehensive (educational) model to evaluate existing networks. A more realistic model would take into account dynamics in network construction. This is even more important if this kind of approach is planned to be used as an absolute reference for existing networks, which are continuously in a 'brownfied state'.

Generating plants were not included in the model of this study, neither at the level of HV meshed network nor at the distribution level. While the amount of dispersed generation (DG) is likely to grow, it would be necessary, for example, to embed DG in the load point modelling. Modelling generation, import and export at the HV system level using an analytic model seems infeasible. Since EHV station service territories are almost without exception heterogeneous, it would anyhow seem sensible to utilize reference network models of HV systems on top of a radial network analytic model.

In suburban small house areas the LV feeder system is the most valuable part of the network (Figure 36). Therefore optimization of the LV system is as important as for the higher voltage levels. The described LV feeder system model is based on fixed joints and branches from an LV trunk. In practice, more complicated LV connection configurations are usually used. Fused joint-boxes for each connection at the branch point or at the connection point (which would require that the main feeder would be circulated at the connection point) could be used to sectionalize the connection branches in LV underground feeder systems. Underground joints are not easily operable in winter conditions and this practice is not common. An alternative with fused disconnection boxes common to several connections and three-phase service cables is applied in nearly all public underground cable systems in Finland.[43] In the branched alternatives no extra excavation is needed because the same route can be utilized as for the main feeder. If multi-connection boxes are used, the extra cost per connection covering the cost of the disconnection boxes and the 'extra' line length has to be taken into account. The large amount of relevant parameters makes it difficult to decide the type and average distance between disconnection boxes in a particular new housing area, even though the general practice for feeder arrangements has been fixed. The optimum distance between disconnection boxes could be obtained using a direct search by varying the number of connections per box, e.g., from 1 to 8 or 12.

In this study the focus was on creating urban zone models which so far had been totally lacking. In rural areas the natural environment classification requires more systematic analysis. There is a general understanding of the effects of winter, windiness, forest cover, etc., but unambiguous data is rare. In Finland's vast area there are geographical and climatic differences between different regions. For instance, temperature zones could be modelled and the combination of forest and snow behaves differently in mountainous areas and near the Baltic Sea compared to some other regions. As was discussed in Section 7.3, the heterogeneity of the rural areas is a problem to be solved in the model network approach. The analytical model could still be improved to include some heterogeneous features of a substation service area. Most probably the load is concentrated near the supply point (HV/MV substation), and the load density then rapidly decreases to a lower level. A sort of 'sector-zone model' could be developed by division of MV feeder sectors to subsectors and zones and by using different load densities in different segments. Thus it would be possible to examine heterogeneous features to some extent. To keep the model unambiguous, symmetry must still be retained.

As was detected in the comparison of 10 kV and 20 kV feeder systems, examining the different voltage levels is a fundamental task in system studies. 1 kV systems, utilized to an increasing extent in Finland, has an impact both on MV and LV systems and is therefore an obligatory supplement to be included.

In reliability analysis only single contingencies in the MV feeder system were studied. The analysis must be extended to cover faults at least in transformer stations and substations. Performance during common mode faults (e.g., large disturbances caused by storms) is a strong driving force in network development in Finland. Single contingencies in TSs and SSs should be a manageable task to model. Vulnerability to large disturbances can be observed easily, but the risks are much harder to quantify. Perhaps bands of probability and the duration of large interruptions could be estimated. Not only the long-duration interruptions (e.g., greater than a few minutes) should be accounted, but short interruptions have to be evaluated as well.

In urban MV networks the applied CIC evaluation base does not necessarily drive reliability improvement (see Figure 43). However, in the latest research[59] significant regional differences were observed. Also, different customer mixes can be evaluated separately since the values are determined for each (composite) customer group. These more service-area-focused values should be applied to the respective areas. For the urban areas the values are considerably higher and using them would perhaps lead to different conclusions.

Finally, it must be remembered that this analytical network model does not cover the whole range of operations of a DNO (see Figure 12). As in the Chilean approach, a model company also including customer service, administration and management, could be constructed and dimensioned to reflect the volume of operation.

8 CONCLUSIONS

The focus of this work was on network cost structure and level depending on external conditions. The basic hypothesis was that the external conditions and load density correlate and that the cost can be presented dependent on load density.

Load density together with a defined customer mix directly determines the supply task, i.e., the number of connection points and their density in a geographical area as well as their load profile. The higher the load density, the higher the connection point density, and the shorter the total line length. Load density indirectly determines the construction conditions since higher load density means a higher building efficiency, which in turn leads to restrictions in land use and more strict structural requirements. Thus, the net economies of density include both cost-rising and cost-lowering factors.

Based on the analysis of urban subdistricts and rural areas, a zonal approach was chosen to model areas with common structural features. The allowed equipment types and their average unit costs were determined for each zone. Customer mixes were modelled per zone; in suburban zones several mixes were applied.

Using a model network approach, cost was determined for networks in rural, suburban, urban and urban core zones. The cost structure and level varies from zone to zone depending on the allowed equipment, share of open space and customer mix. When moving towards the highest load densities in urban and urban core areas, the cost lowering caused by the higher connection point density is attenuated due to the higher unit costs of equipment and route length extensions due to the street-grid topography.

The concentration of loads is a significant cost factor, particularly in rural areas where the share of open space can be as high as 90 %. The larger the share of open space, the higher the concentration of load, and the lower the cost. In urban areas the share of open space is restricted to a few tens of percent and the effect is relatively small in terms of total cost.

The customer mix is an important factor particularly in suburban areas with household loads as a majority. In the areas with more lumped loads (apartment blocks) the cost is lower than in areas with a larger number of scattered smaller load points (small houses). The effect of electrical heating load is of importance in rural areas: when the basic network infrastructure built for other electrical loads is utilized in transferring the energy needed for heating, the greater amount of energy transferred will lead to lower per kWh cost.

The analysis shows a clear pattern of cost relations in different environments. In sparsely populated areas the medium voltage feeder system is dominant. The share of low voltage network level is highest in suburban areas with a high share of small houses, i.e., a high number of small load points each requiring its own cable connection. At highest load densities the relative share of nodal points (transformer stations and substations) is increasing while the line length per connection point is decreasing.

SAIDI, SAIFI and CAIDI indices were determined for a number of sample feeders in different zones to test the model network approach in the evaluation of reliability level. Only the MV feeder system was included in the analysis because it normally characterizes the performance of a distribution system in this sense. Actually, for urban systems this is not quite true because the relative share of nodal points – once again - compared to the length of lines is high and this is reflected in the overall performance indices as well. However, the coarse case studies and a comparison to DNO data show that the distribution system performance can be estimated using a model network approach. Mitigation measures can also be evaluated in the same manner.

Prudence is needed in the application of the model network approach in the comparison of network operators. (1) First of all we have to remember that the network operator's service territory usually contains feeders and substations in divergent environments. The network service area must be divided into subareas that are homogeneous enough, and in the evaluation a weighted sum of different homogeneous areas has to be used to calculate the overall performance. The service areas of MV/LV stations are usually quite homogeneous, but the ranges of high voltage systems are so vast that the equipment service areas can be very heterogeneous. It would be wise to use reference HV networks with the radial distribution network model to receive a realistic output. (2) The network operators may operate a different set of voltage levels. It is quite common, due to historical developments, that a DNO in a big city owns and operates a meshed HV system while in rural areas the operation of the meshed system falls naturally to the grid company. (3) The transformer station and substation operating ranges are determined by the electrical boundary conditions. In urban environments especially, the capacity constraint determines the substation sizes and thereafter the shared infrastructure cost of the feeder system. Companies may have made different choices in the system design regarding the level of reserve capacity and risk management, affecting the capacity constraints. (4) Local historical conditions, such as different medium voltage levels have to be taken into account. (5) The methodology is based on an idealized network model with the cost underestimated, which has to be accounted for in absolute comparisons to the actual networks.

The created analytic and geometric network model, even with massive simplifications, was proven suitable for estimating the network volume and cost for different zones and load densities. The method is not suitable for absolute comparison as such, but it has potential as an auxiliary tool. It could be used to find out parameters that best explain the external conditions, categorize networks, determine weighting factors for other benchmarking methods, etc. Due to all the simplification, this kind of model is not suitable to judge detailed network designs. Instead, it can be used in system level studies and for educational purposes.

The advantages of the model network approach are speed, repeatability and transparency. One can easily determine cost structures and optimal substation spacing with different sets of input data. Most of the suggested improvements and supplements can be realized without losing the analytical nature of the method. Thus the applied methodology forms a qualified framework for further development of the model network approach.

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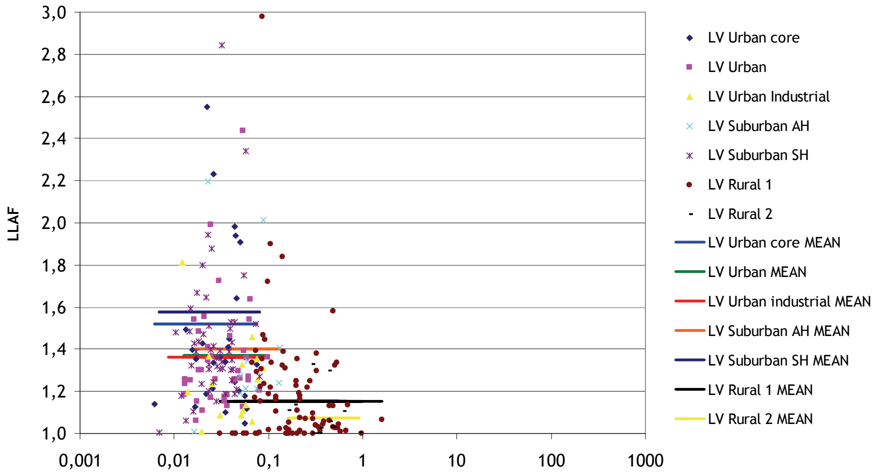
Helsinki subdistricts classified into structural classes - Table of indicators

	Urban core	Urban (mixed)	Suburban Local centres	Suburban Apartment blocks	Suburban Mixed houses	Suburban Small houses	Industrial
Area efficiency e							
low	0,8	0,3	0,26	0,13	0,09	0,05	0,02
med	**1,9**	**0,74**	**0,44**	**0,26**	**0,15**	**0,11**	**0,33**
high	3,3	2,1	0,63	0,52	0,24	0,18	2,1
MV load density (MWh/km^2)							
low	13	3,2	7,0	1,4	1,7	1,3	0,6
med	**41**	**10,9**	**11,5**	**3,6**	**2,9**	**3,1**	**8,1**
high	137	24,9	30	6,9	4,5	6,5	54
Energy density (GWh/km^2)							
low	61	16	34	6,6	7,5	4,3	2,3
med	**216**	**55**	**60**	**16,1**	**12,1**	**10,7**	**41**
high	752	123	159	34,3	21,6	16,8	290
Peak utilization (h/a) med	**5268**	**5046**	**5217**	**4472**	**4172**	**3452**	**5062**
Connection point density (/km^2)							
LV	**273**	**186**	**107**	**114**	**333**	**432**	**74**
MV/LV network stations	**41**	**18**	**18**	**12**	**11**	**11**	**10**
MV customers	**57**	**9**	**6**	**0,9**	**0,048**	**0,07**	**10**
MV total	**98**	**27**	**24**	**12,9**	**11,0**	**11,1**	**20**
Distance between connections (km)							
LV	**0,061**	**0,073**	**0,097**	**0,094**	**0,055**	**0,048**	**0,116**
MV total	**0,101**	**0,192**	**0,204**	**0,278**	**0,301**	**0,301**	**0,224**
Customer density (/km^2)							
LV	**7636**	**6473**	**2572**	**3020**	**1346**	**934**	**639**
MV customers	**77**	**10**	**6**	**0,9**	**0,048**	**0,07**	**12**
Total	**7713**	**6483**	**2578**	**3021**	**1346**	**934**	**651**
Customers per connection							
LV	**28,0**	**34,8**	**24,0**	**26,5**	**4,0**	**2,2**	**8,6**
MV/LV network stations	**186**	**360**	**143**	**252**	**122**	**85**	
MV customers	**1,4**	**1,1**	**1,0**	**1,0**	**1,0**	**1,0**	**1,2**
Population density (/km^2)	**8638**	**9029**	**4326**	**5296**	**2923**	**2071**	**874**
Customers per population	**0,89**	**0,72**	**0,60**	**0,57**	**0,46**	**0,45**	**0,74**
Line length (km/km^2)							
LV	**65,8**	**37,3**	**29,0**	**23,5**	**37,9**	**44,2**	**18,3**
MV	**36,1**	**16,3**	**11,7**	**8,1**	**7,1**	**8,7**	**12,8**
Line per connection (m)							
LV	**241**	**201**	**271**	**206**	**114**	**102**	**247**
MV total	**368**	**604**	**488**	**628**	**643**	**786**	**640**
Line per customer (m)							
LV	**9**	**6**	**11**	**8**	**28**	**47**	**29**
Total	**13**	**8**	**16**	**10**	**33**	**57**	**48**
Customer mix (% of total energy)							
Small houses	0 %	0 %	0 %	2 %	**34 %**	**61 %**	1 %
Row houses	4 %	10 %	5 %	**20 %**	**27 %**	**18 %**	2 %
Apartment blocks	5 %	**20 %**	8 %	**34 %**	**14 %**	6 %	2 %
Agricultural	0 %	0 %	0 %	0 %	0 %	0 %	0 %
Public and commercial	**24 %**	**24 %**	**32 %**	**15 %**	9 %	8 %	**19 %**
Industry	3 %	4 %	2 %	4 %	3 %	1 %	**19 %**
Street lighting	1 %	2 %	1 %	2 %	2 %	2 %	1 %
Public and commercial MV	**56 %**	**36 %**	**49 %**	**18 %**	6 %	2 %	**27 %**
Industry MV	6 %	6 %	3 %	5 %	4 %	1 %	**29 %**
LV total	38 %	59 %	49 %	76 %	90 %	97 %	44 %
MV total	62 %	41 %	51 %	24 %	10 %	3 %	56 %
Energy per connection point (MWh)							
LV	**297**	**174**	**272**	**108**	**33**	**24**	**245**
MV/LV network stations	**1979**	**1796**	**1619**	**1025**	**986**	**940**	**1814**
MV customers	**2366**	**2519**	**5144**	**NC**	**NC**	**NC**	**2286**

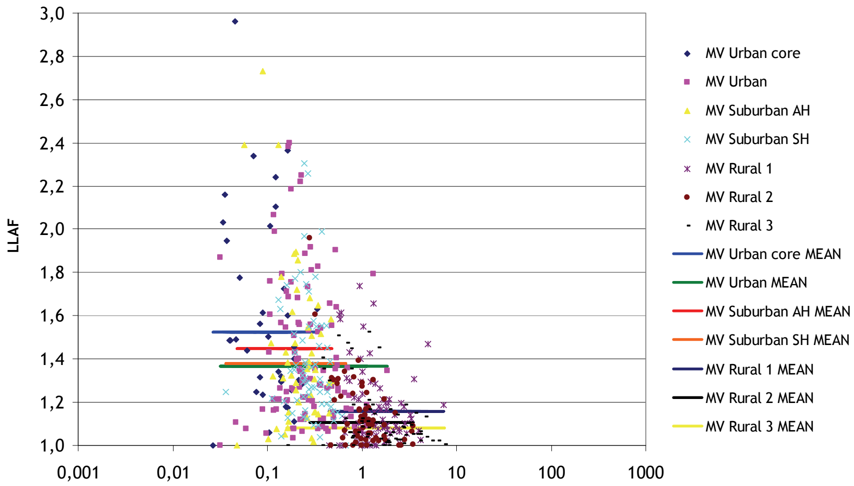
Line length adjustment factors (LLAF)

- the actual line route length per direct distance between end-points based on the analysis of sample areas of Finnish networks

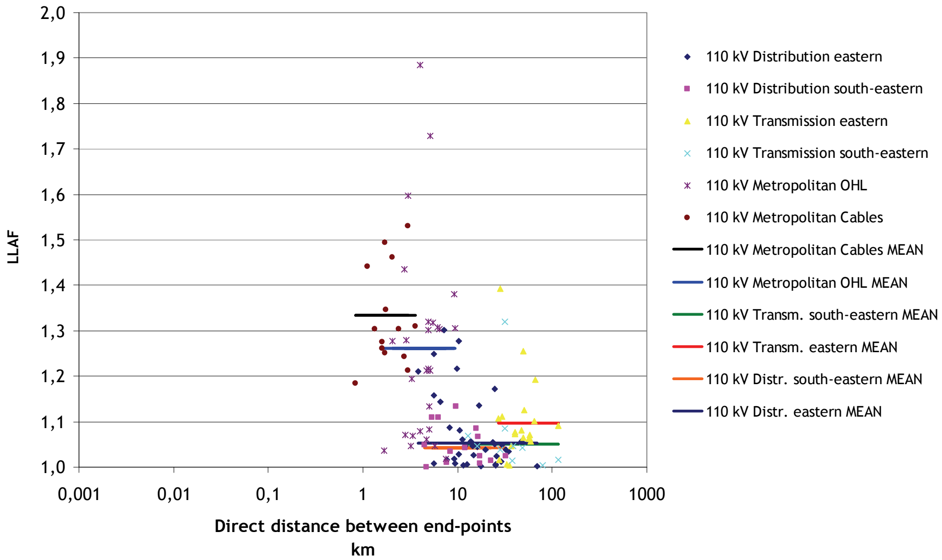
LV lines



MV lines



HV lines



Description tables of the typical structural classes – part 1

Customer mixes

	Rural		Industrial	Suburban: Small houses		Suburban: Mixed houses		Suburban: Apartment blocks	Suburban: Local centre	Urban	City core
Share of open space	40 …80 %			20 … 40 %		20 … 40 %		20 … 40 %	0 … 10 %	10 … 20 %	0 … 10 %
Customer mix		EH			EH		EH				
- households, single-family houses	60 %	20 %	5 %	35 %	3 %	15 %	1 %				
- households, single-family houses, electric heating		40 %			32 %		13 %				
- households, small houses				25 %	2 %	15 %	2 %				
- households, small houses, electric heating					23 %		14 %				
- households, row houses				20 %	2 %	30 %	3 %	20 %		5 %	
- households, row houses, electric heating					18 %		27 %				
- households, apartment blocks				5 %	5 %	15 %	15 %	35 %	10 %	25 %	10 %
- agricultural composite	30 %	30 %									
- commercial and public services composite	10 %	10 %	20 %	10 %	10 %	10 %	10 %	15 %	30 %	25 %	25 %
- industry composite			20 %			5 %	5 %	5 %	5 %	5 %	5 %
- commercial and public services composite MV			20 %	5 %	5 %	10 %	10 %	20 %	50 %	35 %	55 %
- industry composite MV			35 %					5 %	5 %	5 %	5 %
Area of MV customers A_{MVC}	0 %	0 %	72 %	24 %	25 %	29 %	31 %	40 %	30 %	24 %	30 %
Energy density range (GWh/km^2)	0,003 … 2		2 … 300	4 … 17		5 … 20		5 … 35	30 … 160	20 … 125	50 … 750

Restrictions on use of equipment

	Rural	Suburban	Urban	City core
- HV overhead lines	Allowed	Allowed	**Special str./Prohib.**	**Prohibited**
- HV cables in surface soil	Allowed	Allowed	Allowed	**Special str./Prohib.**
- HV cables in tunnels	Allowed	Allowed	Allowed	Allowed
- HV/MV substation AIS	Allowed	**Special str./Prohib.**	**Prohibited**	**Prohibited**
- HV/MV substation GIS in a building	Allowed	Allowed	Allowed	**Special str./Prohib.**
- HV/MV substation GIS underground	Allowed	Allowed	Allowed	Allowed
- Distribution lines, overhead lines	Allowed	Allowed	**Prohibited**	**Prohibited**
- Distribution lines, aerial cables	Allowed	Allowed	**Prohibited**	**Prohibited**
- Distribution lines, cables	Allowed	Allowed	Allowed	**Special str./Prohib.**
- Distribution lines, cables in ducts	Allowed	Allowed	Allowed	Allowed
- MV/LV stations, pole mounted	Allowed	**Prohibited**	**Prohibited**	**Prohibited**
- MV/LV stations, separate house	Allowed	Allowed	**Special str./Prohib.**	**Prohibited**
- MV/LV stations, in buildings	Allowed	Allowed	Allowed	Allowed

Line length adjustment factors

	Rural	Suburban	Urban	City core
- adjustment factor $LLAF_{LV}$	1,1	$\sqrt{2}$	$\sqrt{2}$	$\sqrt{2}$
- adjustment factor $LLAF_{MV}$	1,1	$\sqrt{2}$	$\sqrt{2}$	$\sqrt{2}$
- adjustment factor $LLAF_{HV}$	1,05	1,3	1,3	1,3

Description tables of the typical structural classes – part 2

User group profiles (energy)	SFH	SFHEH	TFH	TFHEH	RH	RHEH	AH	AGRI	SERVC	INDC	SERVCMV	INDCMV
Urban core							10 %		25 %	5 %	55 %	5 %
Urban					5 %		25 %		25 %	5 %	35 %	5 %
Suburban centre							10 %		30 %	5 %	50 %	5 %
Suburban AH					20 %		35 %		15 %	5 %	20 %	5 %
Suburban Mixed	15 %		15 %		30 %		15 %		10 %	5 %	10 %	
Suburban Mixed EH	1 %	13 %	2 %	14 %	3 %	27 %	15 %		10 %	5 %	10 %	
Suburban SH	35 %		25 %		20 %		5 %		10 %		5 %	
Suburban SH EH	3 %	32 %	2 %	23 %	2 %	18 %	5 %		10 %		5 %	
Industrial	5 %								20 %	20 %	20 %	35 %
Rural	60 %							30 %	10 %			
Rural EH	20 %	40 %						30 %	10 %			

Participation coefficients	SFH	SFHEH	TFH	TFHEH	RH	RHEH	AH	AGRI	SERVC	INDC	SERVCMV	INDCMV
Urban core							0,45		1,00	1,00	1,00	1,00
Urban					0,29		0,45		1,00	1,00	1,00	1,00
Suburban centre							0,45		1,00	1,00	1,00	1,00
Suburban AH					1,00		0,99		0,48	0,17	0,48	0,17
Suburban Mixed	0,92		0,92		1,00		0,99		0,48	0,17	0,48	
Suburban Mixed EH	0,42	1,00	0,42	1,00	0,25	1,00	0,36		0,29	0,18	0,29	
Suburban SH	0,92		0,92		1,00		0,99		0,48		0,48	
Suburban SH EH	0,42	1,00	0,42	1,00	0,25	1,00	0,36		0,29		0,29	
Industrial	0,48								1,00	1,00	1,00	1,00
Rural	1,00							1,00	0,47			
Rural EH	1,00	0,65						1,00	0,47			

Velander constants [1)]	SFH	SFHEH	TFH	TFHEH	RH	RHEH	AH	AGRI	SERVC	INDC	SERVCMV	INDCMV
k1	0,30	0,27	0,30	0,27	0,30	0,27	0,30	0,23	0,20	0,18	0,20	0,18
k2	0,00	0,02	0,00	0,02	0,00	0,02	0,00	0,04	0,04	0,11	0,04	0,11

w-coefficients [1)]	SFH	SFHEH	TFH	TFHEH	RH	RHEH	AH	AGRI	SERVC	INDC	SERVCMV	INDCMV
Urban core							0,013		0,050	0,009	0,110	0,009
Urban					0,004		0,033		0,050	0,009	0,070	0,009
Suburban centre							0,013		0,060	0,009	0,100	0,009
Suburban AH					0,060		0,104		0,014	0,002	0,019	0,002
Suburban Mixed	0,041		0,041		0,090		0,044		0,010	0,002	0,010	
Suburban Mixed EH	0,001	0,035	0,003	0,038	0,002	0,073	0,016		0,006	0,002	0,006	
Suburban SH	0,096		0,069		0,060		0,015		0,010		0,005	
Suburban SH EH	0,004	0,086	0,003	0,062	0,002	0,049	0,005		0,006		0,003	
Industrial	0,007								0,040	0,036	0,040	0,063
Rural	0,180							0,069	0,009			
Rural EH	0,060	0,070						0,069	0,009			

sqrt(w)-coefficients [1)]	SFH	SFHEH	TFH	TFHEH	RH	RHEH	AH	AGRI	SERVC	INDC	SERVCMV	INDCMV
Urban core									0,0100	0,0055	0,0220	0,0055
Urban									0,0100	0,0055	0,0140	0,0055
Suburban centre									0,0120	0,0055	0,0200	0,0055
Suburban AH									0,0029	0,0009	0,0038	0,0009
Suburban Mixed									0,0019	0,0009	0,0019	
Suburban Mixed EH		0,0026		0,0028		0,0054			0,0012	0,0010	0,0012	
Suburban SH									0,0019		0,0010	
Suburban SH EH		0,0064		0,0046		0,0036			0,0012		0,0006	
Industrial									0,0080	0,0220	0,0080	0,0385
Rural								0,0120	0,0019			
Rural EH		0,0052						0,0120	0,0019			

Cuctomer interruption costs	SFH	SFHEH	TFH	TFHEH	RH	RHEH	AH	AGRI	SERVC	INDC	SERVCMV	INDCMV
EUR/kW	0,36	0,36	0,36	0,36	0,36	0,36	0,36	0,45	2,37	3,52	2,37	3,52
EUR/kWh	4,29	4,29	4,29	4,29	4,29	4,29	4,29	9,38	24,50	24,45	24,50	24,45

Cuctomer interruption costs	EUR/kW	EUR/kWh
Urban core	2,28	22,47
Urban	1,88	18,43
Suburban centre	2,28	22,47
Suburban AH	1,38	13,38
Suburban Mixed	0,92	9,34
Suburban Mixed EH	0,92	9,34
Suburban SH	0,66	7,32
Suburban SH EH	0,66	7,32
Industrial	2,90	23,46
Rural	0,59	7,84
Rural EH	0,59	7,84

[1)] P [MW], W [GWh]

The applied composite user groups

Deno-tation	Explanation	Load profile index by the Association of Finnish Electric Utilities	Normalized annual energy Er (MWh/a)	Number of customers per connection
SFH	households, single-family house	SLYIND95-601	5	1
SFHEH	households, single-family house, electrical heating	SLYIND95-14	25	1
TFH	households, two-family house	SLYIND95-601	5	2
TFHEH	households, two-family house, electrical heating	SLYIND95-14	25	2
RH	households, row-house	SLYIND95-611	5	9
RHEH	households, row-house, electrical heating	SLYIND95-14	20	5
AH	households, apartment block	SLYIND95-1020	4	54
AGRI	agriculture and household, composite	SLYIND95-712	20	1
SERVC	public and commercial services, composite	SLYIND95-6	50 *	5 **
INDC	industrial, composite	SLYIND95-3	1000 *	1 **

* for MV customers E_r = 3000 MWh/a

** for MV customers n_{cpr} = 1

Line component data

0,4 kV lines	Conductor installed [EUR/km]	Construction cost 1) [EUR/km]	Total unit price [EUR/km]	Maintenance cost [EUR/km,a]	Rated current 2) [A]	Resistance at 20°C [Ω/phase,km]	Reactance 3) [Ω/phase,km]	Earth fault current [A/km]	SC withstand Ith,1s [kA]
0,4 kV twisted air cables (type AMKA)									
Al 16	6 258	6 462	12 720	75	70	1,910	0,108	-	1,0
Al 25	6 258	6 462	12 720	75	90	1,200	0,106	-	1,6
Al 35	6 719	6 011	12 730	75	115	0,868	0,104	-	2,3
Al 50	6 719	6 011	12 730	75	140	0,641	0,101	-	3,2
Al 70	9 049	7 601	16 650	75	180	0,443	0,097	-	4,5
Al 120	11 171	6 689	17 860	75	250	0,253	0,092	-	7,8
0,4 kV underground cables (type AHXK) - rural 4)									
Al 16	6 730	7 773	14 503	50	78	1,910	0,091	-	1,5
Al 25	6 730	7 773	14 503	50	100	1,200	0,088	-	2,4
Al 35	9 360	7 773	17 133	50	125	0,870	0,088	-	3,4
Al 50	9 360	7 773	17 133	50	150	0,640	0,088	-	4,8
Al 70	11 040	7 773	18 813	50	185	0,450	0,085	-	6,7
Al 95	12 750	7 773	20 523	50	220	0,330	0,085	-	9,0
Al 120	12 750	7 773	20 523	50	255	0,260	0,082	-	11,4
Al 150	20 840	7 773	28 613	50	290	0,210	0,082	-	14,2
Al 185	20 840	7 773	28 613	50	330	0,170	0,082	-	17,5
Al 2 x 185	41 680	7 773	49 453	50	598	0,085	0,041	-	17,5
Al 3 x 185	62 520	7 773	70 293	50	897	0,057	0,027	-	17,5
Al 240	24 090	7 773	31 863	50	375	0,130	0,079	-	22,6
Al 300	24 090	7 773	31 863	50	430	0,110	0,079	-	28,2
0,4 kV underground cables (type AHXK) - densely populated areas 5)									
Al 16	6 730	19 057	25 787	80	78	1,910	0,091	-	1,5
Al 25	6 730	19 057	25 787	80	100	1,200	0,088	-	2,4
Al 35	9 360	19 057	28 417	80	125	0,870	0,088	-	3,4
Al 50	9 360	19 057	28 417	80	150	0,640	0,088	-	4,8
Al 70	11 040	19 057	30 097	80	185	0,450	0,085	-	6,7
Al 95	12 750	19 057	31 807	80	220	0,330	0,085	-	9,0
Al 120	12 750	19 057	31 807	80	255	0,260	0,082	-	11,4
Al 150	20 840	19 057	39 897	80	290	0,210	0,082	-	14,2
Al 185	20 840	19 057	39 897	80	330	0,170	0,082	-	17,5
Al 2 x 185	41 680	19 057	60 737	80	598	0,085	0,041	-	17,5
Al 3 x 185	62 520	19 057	81 577	80	897	0,057	0,027	-	17,5
Al 240	24 090	19 057	43 147	80	375	0,130	0,079	-	22,6
Al 300	24 090	19 057	43 147	80	430	0,110	0,079	-	28,2
0,4 kV underground cables (type AHXK) - city 6)									
Al 16	6 730	31 215	37 945	100	78	1,910	0,091	-	1,5
Al 25	6 730	31 215	37 945	100	100	1,200	0,088	-	2,4
Al 35	9 360	31 215	40 575	100	125	0,870	0,088	-	3,4
Al 50	9 360	31 215	40 575	100	150	0,640	0,088	-	4,8
Al 70	11 040	31 215	42 255	100	185	0,450	0,085	-	6,7
Al 95	12 750	31 215	43 965	100	220	0,330	0,085	-	9,0
Al 120	12 750	31 215	43 965	100	255	0,260	0,082	-	11,4
Al 150	20 840	31 215	52 055	100	290	0,210	0,082	-	14,2
Al 185	20 840	31 215	52 055	100	330	0,170	0,082	-	17,5
Al 2 x 185	41 680	31 215	72 895	100	598	0,085	0,041	-	17,5
Al 3 x 185	62 520	31 215	93 735	100	897	0,057	0,027	-	17,5
Al 240	24 090	31 215	55 305	100	375	0,130	0,079	-	22,6
Al 300	24 090	31 215	55 305	100	430	0,110	0,079	-	28,2

20 kV lines	Conductor installed [EUR/km]	Construction cost 1) [EUR/km]	Total unit price [EUR/km]	Maintenance cost [EUR/km,a]	Rated current 2) [A]	Resistance at 20°C [Ω/phase,km]	Reactance 3) [Ω/phase,km]	Earth fault current [A/km]	SC withstand Ith,1s [kA]
20 kV overhead lines (type ACSR)									
Al/Fe 21/4	6 541	11 999	18 540	130	155	1,350	~0,40	~0,06	1,5
Al/Fe 34/6	6 541	11 999	18 540	130	210	0,848	~0,38	~0,06	3,2
Al/Fe 42/25	8 707	11 453	20 160	130	250	0,682	~0,38	~0,06	4,0
Al/Fe 54/9	8 707	11 453	20 160	130	280	0,536	~0,37	~0,07	5,0
Al/Fe 75/14	10 397	11 973	22 370	130	335	0,380	~0,36	~0,07	7,1
Al/Fe 85/14	10 397	11 973	22 370	130	360	0,337	~0,35	~0,07	8,0
20 kV underground cables (type AHXAMKW) - rural 4)									
Al 70	33 160	10 600	43 760	30	155	0,443	0,132	2,1	6,6
Al 95	36 740	10 600	47 340	30	190	0,320	0,126	2,3	6,9
Al 120	36 740	10 600	47 340	30	210	0,253	0,123	2,5	11,3
Al 150	43 860	10 600	54 460	30	240	0,206	0,116	2,6	14,1
Al 185	43 860	10 600	54 460	30	270	0,164	0,113	2,8	17,4
Al 240	46 310	10 600	56 910	30	335	0,125	0,110	3,3	22,6
Al 300	46 310	10 600	56 910	30	375	0,100	0,107	3,5	28,3

20 kV lines contd.

	Conductor installed [EUR/km]	Construction cost 1) [EUR/km]	Total unit price [EUR/km]	Maintenance cost [EUR/km,a]	Rated current 2) [A]	Resistance at 20°C [Ω/phase,km]	Reactance 3) [Ω/phase,km]	Earth fault current [A/km]	SC withstand Ith,1s [kA]
20 kV underground cables (type AHXAMKW) - densely populated areas 5)									
Al 70	33 160	27 792	60 952	40	155	0,451	0,132	2,1	6,6
Al 95	36 740	27 792	64 532	40	190	0,329	0,126	2,3	6,9
Al 120	36 740	27 792	64 532	40	210	0,262	0,123	2,5	11,3
Al 150	43 860	27 792	71 652	40	240	0,216	0,116	2,6	14,1
Al 185	43 860	27 792	71 652	40	270	0,175	0,113	2,8	17,4
Al 240	46 310	27 792	74 102	40	335	0,138	0,110	3,3	22,6
Al 300	46 310	27 792	74 102	40	375	0,114	0,107	3,5	28,3
20 kV underground cables (type AHXAMKW) - city 6)									
Al 70	33 160	48 023	81 183	50	155	0,451	0,132	2,1	6,6
Al 95	36 740	48 023	84 763	50	190	0,329	0,126	2,3	6,9
Al 120	36 740	48 023	84 763	50	210	0,262	0,123	2,5	11,3
Al 150	43 860	48 023	91 883	50	240	0,216	0,116	2,6	14,1
Al 185	43 860	48 023	91 883	50	270	0,175	0,113	2,8	17,4
Al 240	46 310	48 023	94 333	50	335	0,138	0,110	3,3	22,6
Al 300	46 310	48 023	94 333	50	375	0,114	0,107	3,5	28,3

110 kV lines

	Conductor installed [EUR/km]	Construction cost 1) [EUR/km]	Total unit price [EUR/km]	Maintenance cost [EUR/km,a]	Rated current 2) [A]	Resistance at 20°C [Ω/phase,km]	Reactance 3) [Ω/phase,km]	Earth fault current [A/km]	SC withstand Ith,1s [kA]
110 kV overhead lines - wooden poles									
Single circuit Al/Fe 106/25	9 072	43 404	52 476	1 000	430	0,2730	~ 0,42	~ 0,32	10,0
Single circuit Al/Fe 152/25	12 960	52 513	65 473	1 000	550	0,1900	~ 0,41	~ 0,33	14,3
Single circuit Al/Fe 205/33	12 960	65 803	78 763	1 000	660	0,1450	~ 0,40	~ 0,33	18,9
Single circuit Al/Fe 305/39	18 468	86 460	104 928	1 000	845	0,1000	~ 0,39	~ 0,35	28,7
Double circuit Al/Fe 106/25	18 144	86 808	104 952	1 000	860	0,1365	~ 0,42	~ 0,29	10,0
Double circuit Al/Fe 152/25	25 920	105 027	130 947	1 000	1100	0,0950	~ 0,41	~ 0,30	14,3
Double circuit Al/Fe 205/33	25 920	131 605	157 525	1 000	1320	0,0725	~ 0,40	~ 0,30	18,9
Double circuit Al/Fe 305/39	36 936	172 919	209 855	1 000	1690	0,0500	~ 0,39	~ 0,32	28,7
110 kV overhead lines - steel towers									
Single circuit Al/Fe 106/25	9 072	120 528	129 600	1 000	430	0,2730	~ 0,41	~ 0,32	10,0
Single circuit Al/Fe 152/25	12 960	147 312	160 272	1 000	550	0,1900	~ 0,40	~ 0,33	14,3
Single circuit Al/Fe 205/33	12 960	174 096	187 056	1 000	660	0,1450	~ 0,39	~ 0,33	18,9
Single circuit Al/Fe 305/39	18 468	200 880	219 348	1 000	845	0,1000	~ 0,38	~ 0,35	28,7
Single circuit 2 x Al/Fe 305/39	36 936	219 897	256 833	1 000	1280	0,0490	~ 0,27	~ 0,35	(28,7)
Single circuit Al/Fe 565/72	27 216	254 448	281 664	1 000	1240	0,0540	~ 0,36	~ 0,37	53,1
Single circuit 2 x Al/Fe 565/72	54 432	281 232	335 664	1 000	1880	0,0270	~ 0,26	~ 0,37	(53,1)
Double circuit Al/Fe 106/25	18144	145 800	163 944	1 000	860	0,1365	~ 0,43	~ 0,29	10,0
Double circuit Al/Fe 152/25	25920	178 200	204 120	1 000	1100	0,0950	~ 0,42	~ 0,30	14,3
Double circuit Al/Fe 205/33	25920	210 600	236 520	1 000	1320	0,0725	~ 0,41	~ 0,30	18,9
Double circuit Al/Fe 305/39	36936	243 000	279 936	1 000	1690	0,0500	~ 0,40	~ 0,32	28,7
Double circuit 2 x Al/Fe 305/39	73872	266 004	339 876	1 000	2560	0,0245	~ 0,29	~ 0,32	(28,7)
Double circuit Al/Fe 565/72	54432	307 800	362 232	1 000	2480	0,0270	~ 0,38	~ 0,34	53,1
Double circuit 2 x Al/Fe 565/72	108864	340 200	449 064	1 000	3760	0,0135	~ 0,27	~ 0,34	(53,1)
110 kV cables (PEX types AHXLMK and HXLMK) - suburban									
Al 300	129 000	300 000	429 000	1 000	410	0,1070	0,132	9,9	28,3
Al 800	165 000	300 000	465 000	1 000	675	0,0480	0,113	13,8	75,6
Cu 1200	300 000	300 000	600 000	1 000	985	0,0250	0,110	16,8	171,1
Cu 2000	465 000	300 000	765 000	1 000	1130	0,0220	0,101	24,6	285,7
110 kV cables (PEX types AHXLMK and HXLMK) - city									
Al 300	129 000	600 000	729 000	2 000	390	0,1250	0,132	9,9	28,3
Al 800	165 000	600 000	765 000	2 000	670	0,0530	0,113	13,8	75,6
Cu 1200	300 000	600 000	900 000	2 000	1100	0,0192	0,110	16,8	171,1
Cu 2000	465 000	600 000	1 065 000	2 000	1400	0,0117	0,101	24,6	285,7

1) Erection of poles, cable channels and pipes, earthwork, including material
2) Typical values
3) Typical values, reactance of cables in Δ configuration
4) Shared trenching factor 1,5
5) Shared trenching factor 1,75
6) Shared trenching factor 2

20/0,4 kV transformer station component data

	Nominal losses P_{0N} [kW]	Nominal losses P_{kN} [kW]	Investment costs: Trans-former [kEUR]	20 kV line disconnector (pole-mounted) [kEUR]	20 kV RMU unit (in buildings) [kEUR]	0,4 feeder connection (in buildings) [kEUR]	Cost of construction (pole-mounted) [kEUR]	Cost of TS building (in buildings) [kEUR]	Maintenance cost: Pole-mounted unit [EUR/unit,a]	TS in a building [EUR/unit,a]
30 kVA	0,10	0,59	2,61	3,0	5,5	5,0	3,8	30	70	130
50 kVA	0,14	0,89	2,61	3,0	5,5	5,0	3,8	30	70	130
100 kVA	0,22	1,49	2,98	3,0	5,5	5,0	3,8	30	70	130
200 kVA	0,42	2,30	3,78	3,0	5,5	5,0	6,6	30	70	130
315 kVA	0,60	4,50	4,60	3,0	5,5	5,0	6,6	30	70	130
500 kVA	0,72	6,60	6,07	3,0	5,5	5,0	6,6	30	70	130
630 kVA	0,89	7,20	8,20	3,0	5,5	5,0	6,6	30	70	130
800 kVA	1,20	8,50	9,76	3,0	5,5	5,0	6,6	30	70	130
1000 kVA	1,45	10,20	12,18	3,0	5,5	5,0	9,3	30	70	130
1250 kVA	1,60	11,50	15,92	3,0	5,5	5,0	9,3	30	70	130
1600 kVA	1,84	14,10	19,57	3,0	5,5	5,0	9,3	30	70	130

110/20 kV substation component data

Transformers

	Nominal losses P_{0N} [kW]	Nominal losses P_{kN} [kW]	Investment costs: Trans-former [kEUR]	Investment costs: Secondary & auxiliary [kEUR]	Maintenance costs: Trans-former [EUR/unit,a]	Maintenance costs: Secondary & auxiliary [EUR/unit,a]	Maintenance costs: Building [EUR/unit,a]	Building floor space requirement: Rural [m^2]	Suburban [m^2]	Urban [m^2]	Urban under-ground [m^2]	Lot space requirement: Rural [m^2]	Suburban [m^2]	Urban [m^2]	Urban under-ground [m^2]
10 MVA	9,0	51	177	32	2 500	560	500	50	50	70	140	250	250	250	0
16 MVA	11,0	74	284	32	2 500	560	500	60	60	80	180	250	250	250	0
20 MVA	13,5	87	305	32	2 500	560	500	70	70	90	200	250	250	250	0
25 MVA	15,5	100	327	32	3 000	560	500	80	80	100	220	250	250	250	0
31,5 MVA	18,0	122	382	32	3 000	560	500	90	90	110	250	250	250	250	0
40 MVA	23,5	146	425	32	3 000	560	500	90	90	120	250	250	250	250	0
50 MVA	27,0	175	507	32	3 000	560	500	100	100	130	270	250	250	250	0
63 MVA	32,0	210	583	32	3 000	560	500	110	110	140	290	250	250	250	0

Switchgear

	Investment costs: Primary unit (bay) [kEUR]	Investment costs: Secondary & auxiliary [kEUR]	Maintenance costs: Primary unit (bay) [EUR/unit,a]	Maintenance costs: Secondary & auxiliary [EUR/unit,a]	Maintenance costs: Building [EUR/unit,a]	Building: Floor space requirement [m^2]	Land: Lot space requirement [m^2]
110 kV unit (bay) - Rural AIS	300	77	1 500	1 700	300	19	1 500
110 kV unit (bay) - Suburban AIS	300	77	1 500	1 700	300	19	1 500
110 kV unit (bay) - Urban GIS	454	77	1 500	1 700	1 000	76	192
110 kV unit (bay) - Urban GIS underground	454	77	1 500	1 700	1 000	150	0
20 kV unit (bay) - Rural indoors	38	22	200	500	360	30	70
20 kV unit (bay) - Suburban indoors	38	22	200	500	360	30	70
20 kV unit (bay) - Urban indoors	38	22	200	500	400	30	70
20 kV unit (bay) - Urban underground	38	22	200	500	400	60	0

Buildings and Land

	Building cost: Rural [EUR/m^2]	Building cost: Suburban [EUR/m^2]	Building cost: Urban [EUR/m^2]	Building cost: Urban underground [EUR/m^2]	Price of land: Rural [EUR/m^2]	Price of land: Suburban [EUR/m^2]	Price of land: Urban [EUR/m^2]	Price of land: Urban underground [EUR/m^2]
Transformer buildings	800	1 000	1 000	1 500	2	60	200	NR
Switchgear buildings	1 000	1 200	1 500	1 500	2	60	200	NR

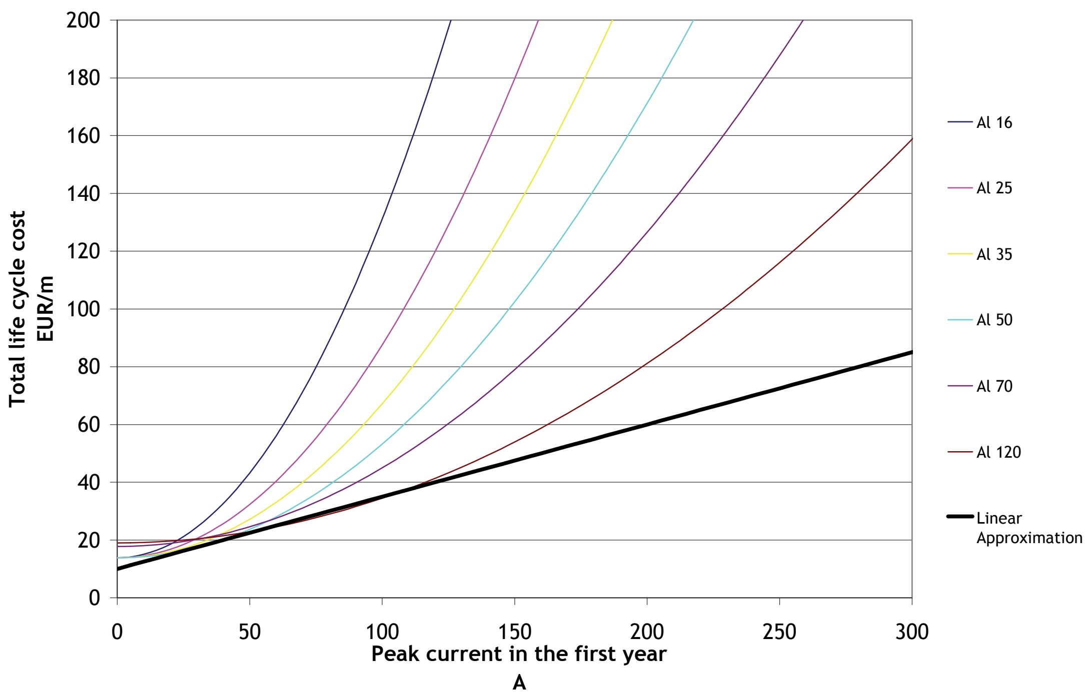
Sources of data:
- Unit prices for the components in electricity distribution networks for the year 2007, the Finnish Energy Market Authority
- Helen Electricity Network Ltd
- Kainuun Sähköverkko Oy
- Prysmian Cables and Systems power cable catalogs 2006
- ABB Handbook Technical Data and Tables 2000-07
- Purchase Price Statistics of Real Estates, Land Survey of Finland

Linear cost function approximation
- 0,4 kV twisted aerial cables (type AMKA)

Interest rate [%]	6
Load growth rate [%/year]	0,12
Life cycle [years]	40
Time of load growth [years]	40
Peak utilization [h/year]	3000
Price of power losses [EUR/kVA,year]	80,00
Price of no-load energy losses [EUR/kWh]	0,03
Price of load energy losses [EUR/kWh]	0,04
Nominal voltage [kV]	0,4

Conductor size [mm²]	**Al 16**	**Al 25**	**Al 35**	**Al 50**	**Al 70**	**Al 120**
Conductor price [EUR/m]	6,26	6,26	6,72	6,72	9,05	11,17
Construction cost [EUR/m]	6,46	6,46	6,01	6,01	7,60	6,69
Conductor resistance [Ω/m]	0,00191	0,0012	0,000868	0,000641	0,000443	0,000253
Current rating [A]	70	90	115	140	180	250
Conductor max temperature [°C]	70	70	70	70	70	70

Maintenance						
Maintenance cost [EUR/km,a]	75	75	75	75	75	75



Area	f_1 EUR/m	f_2 EUR/m	f_3 EUR/m	f_{total} EUR/m	v EUR·10^{-3}/A,m
All	5,0	0,0	5,0	10,0	250

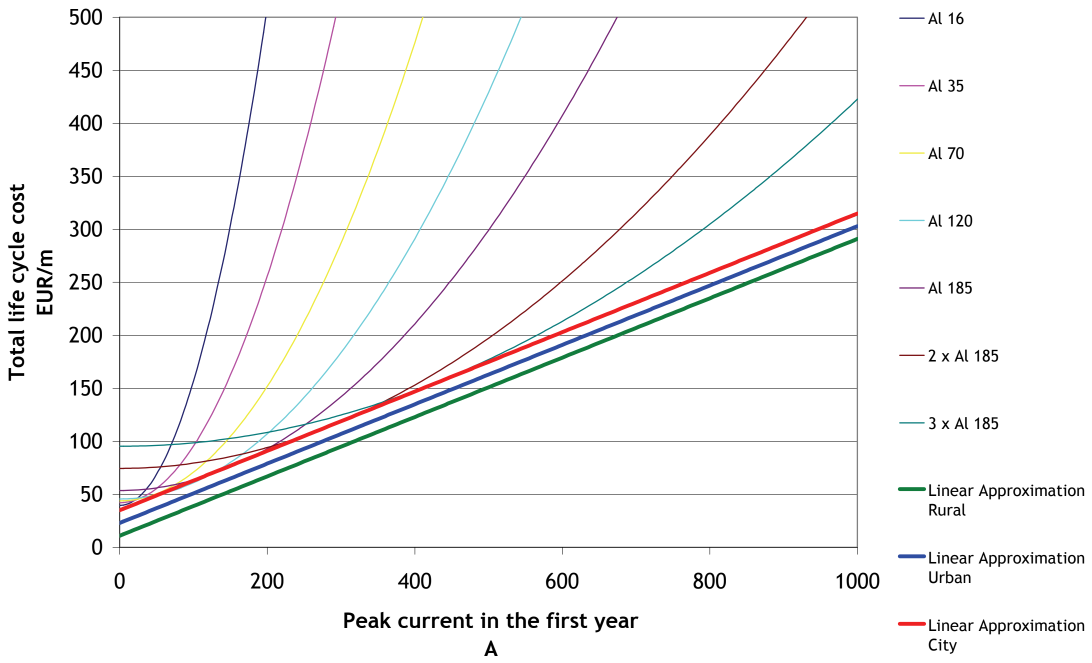
Cost approximation = [$(f_1 + f_2 + f_3) + v \cdot 10^{-3} \cdot$Current/A]·Line length/m

Linear cost function approximation - 0,4 kV cables (type AHXK)

Interest rate [%]	6
Load growth rate [%/year]	0,12
Life cycle [years]	40
Time of load growth [years]	40
Peak utilization [h/year]	3000
Price of power losses [EUR/kVA,year]	80,00
Price of no-load energy losses [EUR/kWh]	0,03
Price of load energy losses [EUR/kWh]	0,04
Nominal voltage [kV]	0,4

Conductor size [mm^2]	Al 16	Al 35	Al 70	Al 120	Al 185	2 x Al 185	3 x Al 185
Conductor price [EUR/m]	6,73	9,36	11,04	12,75	20,84	41,68	62,52
Construction cost - rural [EUR/m]	7,77	7,77	7,77	7,77	7,77	7,77	7,77
Construction cost - urban [EUR/m]	19,06	19,06	19,06	19,06	19,06	19,06	19,06
Construction cost - city [EUR/m]	31,22	31,22	31,22	31,22	31,22	31,22	31,22
Conductor resistance [Ω/m]	0,00191	0,00087	0,00044	0,00025	0,00016	0,00008	5,33E-05
Current rating [A]	73	120	177	237	299	598	897
Conductor max temperature [˚C]	65	65	65	65	65	65	65

Maintenance							
Maintenance cost - rural [EUR/km,a]	50	50	50	50	50	50	50
Maintenace cost - urban [EUR/km,a]	80	80	80	80	80	80	80
Maintenance cost - city [EUR/km,a]	110	110	110	110	110	110	110



Area	f_1 EUR/m	f_2 EUR/m	f_3 EUR/m	f_{total} EUR/m	v EUR·10^{-3}/A,m
Rural	5,0	1,7	4,3	11,0	280
Urban	5,0	1,7	16,3	23,0	280
City	5,0	1,7	28,3	35,0	280

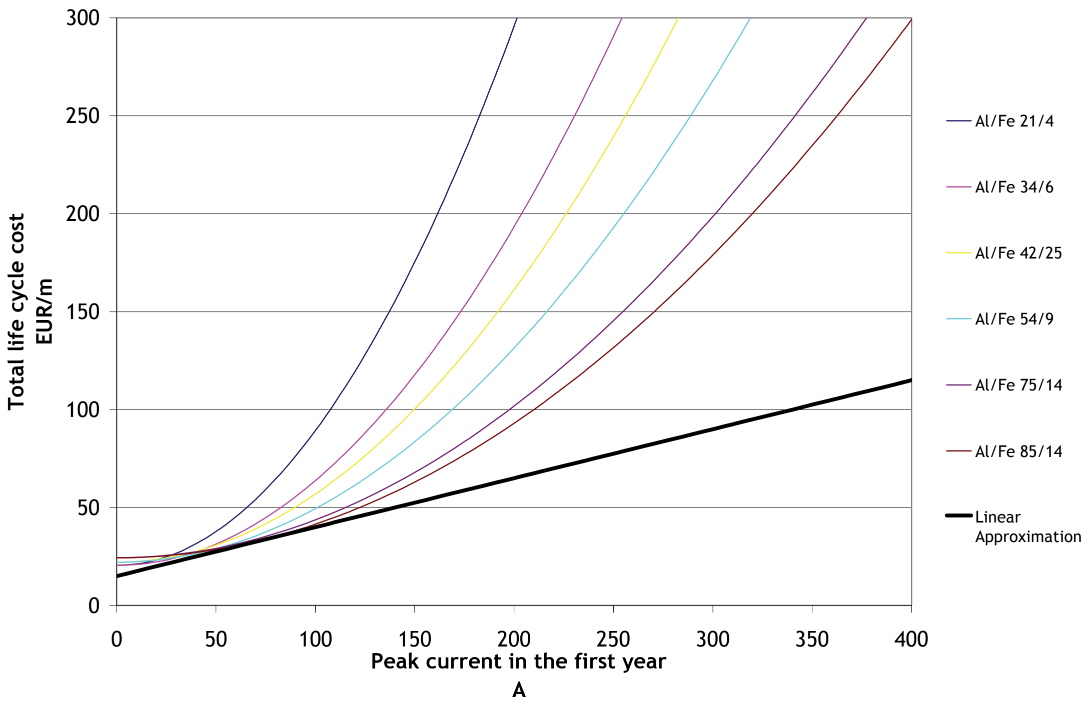
Cost approximation = [$(f_1 + f_2 + f_3) + v \cdot 10^{-3} \cdot$Current/A]·Line length/m

Linear cost function approximation - 20 kV overhead lines

Interest rate [%]	6
Load growth rate [%/year]	0,12
Life cycle [years]	40
Time of load growth [years]	40
Peak utilization [h/year]	4000
Price of power losses [EUR/kVA,year]	25,00
Price of no-load energy losses [EUR/kWh]	0,03
Price of load energy losses [EUR/kWh]	0,04
Nominal voltage [kV]	20

Conductor size [mm²]	**Al/Fe 21/4**	**Al/Fe 34/6**	**Al/Fe 42/25**	**Al/Fe 54/9**	**Al/Fe 75/14**	**Al/Fe 85/14**
Conductor price [EUR/m]	6,54	6,54	8,71	8,71	10,40	10,40
Construction cost [EUR/m]	12,00	12,00	11,45	11,45	11,97	11,97
Conductor resistance [Ω/m]	0,00135	0,000848	0,000682	0,000536	0,00038	0,000337
Current rating [A]	155	210	250	280	335	360
Conductor max temperature [°C]	80	80	80	80	80	80

Maintenance						
Maintenance cost [EUR/km,a]	130	130	130	130	130	130



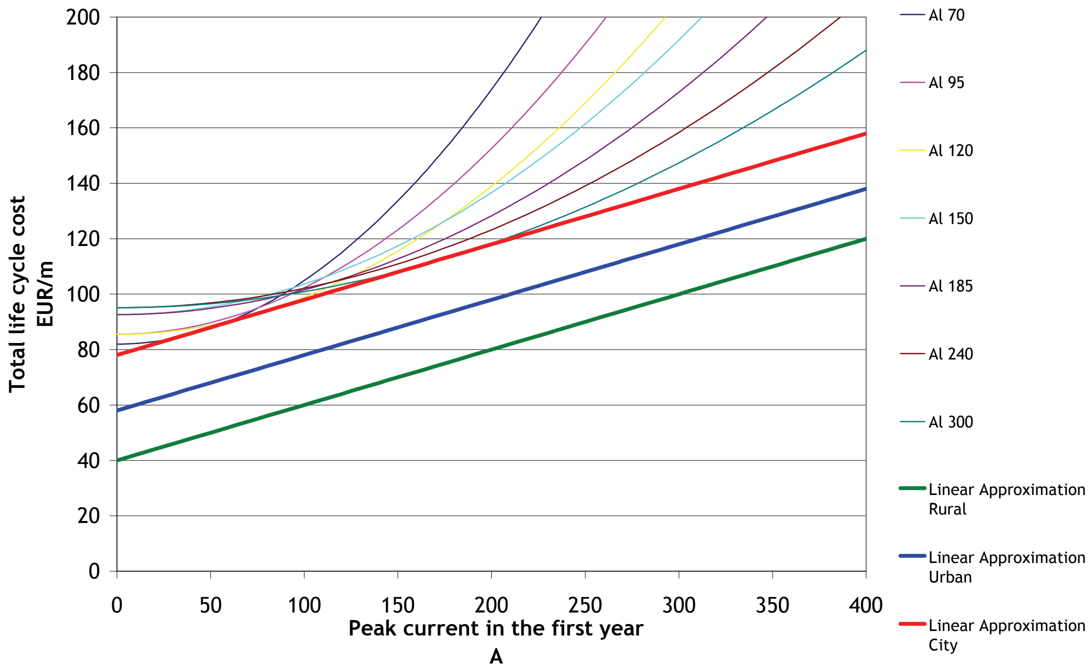
Area	**f_1 EUR/m**	**f_2 EUR/m**	**f_3 EUR/m**	**f_{total} EUR/m**	**v EUR·10^{-3}/A,m**
All	6,0	0,0	9,0	15,0	250

Cost approximation = [$(f_1 + f_2 + f_3) + v \cdot 10^{-3} \cdot$ Current/A]·Line length/m

Linear cost function approximation - 20 kV cables

Interest rate [%]	6
Load growth rate [%/year]	0,12
Life cycle [years]	40
Time of load growth [years]	40
Peak utilization [h/year]	4000
Price of power losses [EUR/kVA,year]	25,00
Price of no-load energy losses [EUR/kWh]	0,03
Price of load energy losses [EUR/kWh]	0,04
Nominal voltage [kV]	20

Conductor size [mm^2]	Al 70	Al 95	Al 120	Al 150	Al 185	Al 240	Al 300
Conductor price [EUR/m]	33,16	36,74	36,74	43,86	43,86	46,31	46,31
Construction cost - rural [EUR/m]	10,60	10,60	10,60	10,60	10,60	10,60	10,60
Construction cost - urban [EUR/m]	27,79	27,79	27,79	27,79	27,79	27,79	27,79
Construction cost - city [EUR/m]	48,02	48,02	48,02	48,02	48,02	48,02	48,02
Conductor resistance [Ω/m]	0,000451	0,000329	0,000262	0,000216	0,000175	0,000138	1,14E-04
Current rating [A]	155	190	210	240	270	335	375
Conductor max temperature [˚C]	65	65	65	65	65	65	65
Maintenance							
Maintenance cost - rural [EUR/km,a]	30	30	30	30	30	30	30
Maintenance cost - urban [EUR/km,a]	40	40	40	40	40	40	40
Maintenance cost - city [EUR/km,a]	50	50	50	50	50	50	50



Area	f_1 EUR/m	f_2 EUR/m	f_3 EUR/m	f_{total} EUR/m	v EUR·10^{-3}/A,m
Rural	6,0	27,2	6,8	40,0	200
Urban	6,0	27,2	24,8	58,0	200
City	6,0	27,2	44,8	78,0	200

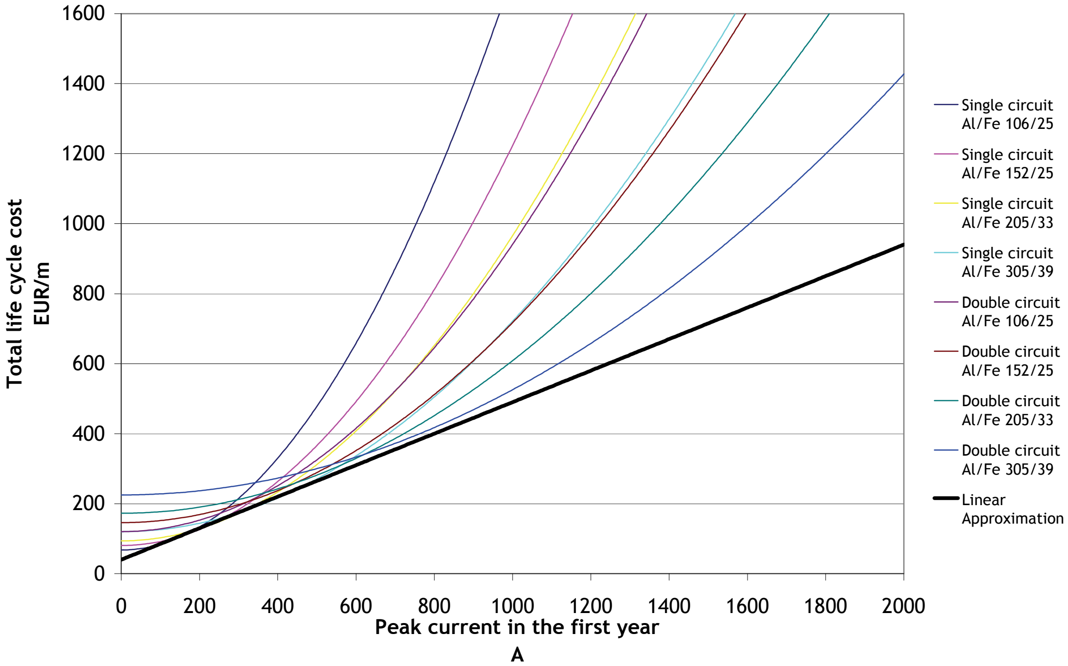
Cost approximation = [$(f_1 + f_2 + f_3) + v \cdot 10^{-3} \cdot$Current/A]·Line length/m

Linear cost function approximation
- 110 kV overhead lines, wooden poles

Interest rate [%]	6
Load growth rate [%/year]	0,12
Life cycle [years]	40
Time of load growth [years]	40
Peak utilization [h/year]	5000
Price of power losses [EUR/kVA,year]	5,00
Price of no-load energy losses [EUR/kWh]	0,03
Price of load energy losses [EUR/kWh]	0,04
Nominal voltage [kV]	110

	Single circuit Al/Fe				Double circuit Al/Fe			
Conductor size [mm^2]	**106/25**	**152/25**	**205/33**	**305/39**	**106/25**	**152/25**	**205/33**	**305/39**
Conductor price [EUR/m]	9,07	12,96	12,96	18,47	18,14	25,92	25,92	36,94
Construction cost [EUR/m]	43,40	52,51	65,80	86,46	86,81	105,03	131,61	172,92
Conductor resistance [Ω/m]	0,000273	0,00019	0,000145	0,0001	0,0001365	0,000095	7,25E-05	5,00E-05
Current rating [A]	430	550	660	845	860	1100	1320	1690
Conductor max temperature [˚C]	80	80	80	80	80	80	80	80

Maintenance								
Maintenance cost [EUR/km,a]	1000	1000	1000	1000	1000	1000	1000	1000



Area	f_1 **EUR/m**	f_2 **EUR/m**	f_3 **EUR/m**	f_{total} **EUR/m**	v **EUR·10^{-3}/A,m**
All	9,0	0,0	31,0	40,0	450

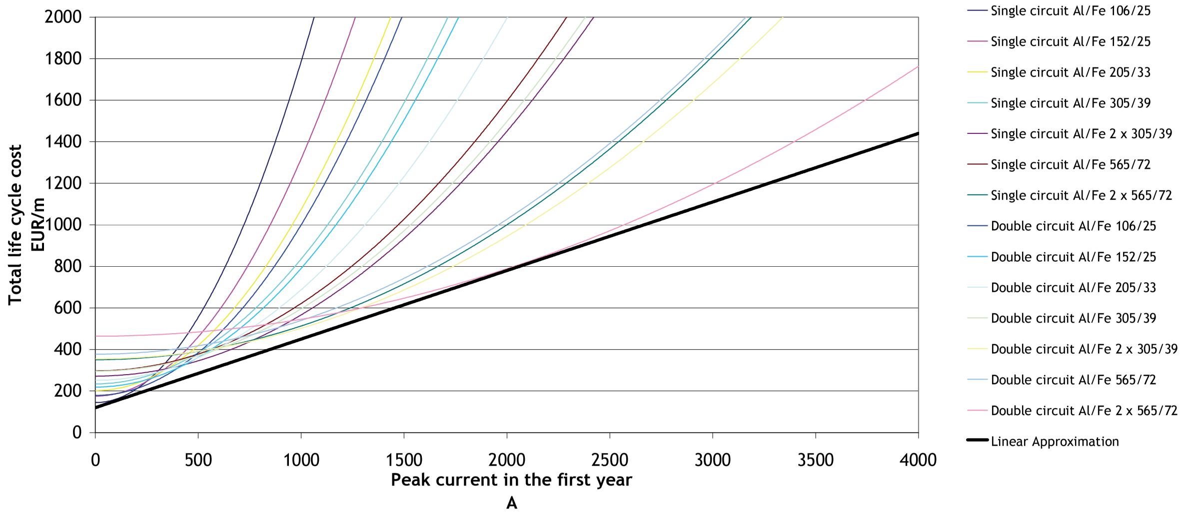
Cost approximation = [$(f_1 + f_2 + f_3) + v \cdot 10^{-3} \cdot$Current/A]·Line length/m

Linear cost function approximation
- 110 kV overhead lines, steel towers

Interest rate [%]	6
Load growth rate [%/year]	0,12
Life cycle [years]	40
Time of load growth [years]	40
Peak utilization [h/year]	5000
Price of power losses [EUR/kVA,year]	5,00
Price of no-load energy losses [EUR/kWh]	0,03
Price of load energy losses [EUR/kWh]	0,04
Nominal voltage [kV]	110

	Single circuit Al/Fe							Double circuit Al/Fe						
Conductor size [mm^2]	106/25	152/25	205/33	305/39	2 x 305/39	565/72	2 x 565/72	106/25	152/25	205/33	305/39	2 x 305/39	565/72	2 x 565/72
Conductor price [EUR/m]	9,07	12,96	12,96	18,47	36,94	27,22	54,43	18,14	25,92	25,92	36,94	73,87	54,43	108,86
Construction cost [EUR/m]	120,53	147,31	174,10	200,88	219,90	254,45	281,23	145,80	178,20	210,60	243,00	266,00	307,80	340,20
Conductor resistance [Ω/m]	2,73E-04	1,90E-04	1,45E-04	1,00E-04	4,90E-05	5,40E-05	2,70E-05	1,37E-04	9,50E-05	7,25E-05	5,00E-05	2,45E-05	2,70E-05	1,35E-05
Current rating [A]	430	550	660	845	1280	1240	1880	860	1100	1320	1690	2560	2480	3760
Conductor max temperature [°C]	80	80	80	80	80	80	80	80	80	80	80	80	80	80

Maintenance														
Maintenance cost [EUR/km,a]	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000



Area	f_1 EUR/m	f_2 EUR/m	f_3 EUR/m	f_{total} EUR/m	v EUR·10^{-3}/A,m
All	9,0	0,0	111,0	120,0	330

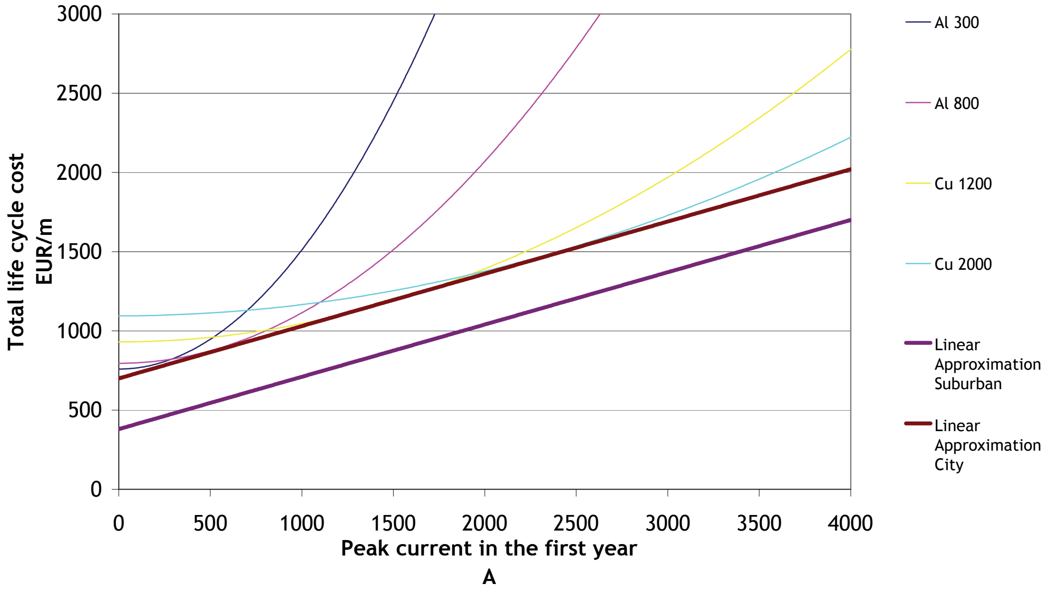
Cost approximation = $[\,(f_1 + f_2 + f_3) + v \cdot 10^{-3} \cdot \text{Current/A}\,] \cdot \text{Line length/m}$

Linear cost function approximation - 110 kV cables

Interest rate [%]	6
Load growth rate [%/year]	0,12
Life cycle [years]	40
Time of load growth [years]	40
Peak utilization [h/year]	5000
Price of power losses [EUR/kVA,year]	5,00
Price of no-load energy losses [EUR/kWh]	0,03
Price of load energy losses [EUR/kWh]	0,04
Nominal voltage [kV]	110

Conductor size [mm²]	**Al 300**	**Al 800**	**Cu 1200**	**Cu 2000**
Conductor price [EUR/m]	129	165	300	465
Construction cost - suburban [EUR/m]	300	300	300	300
Construction cost - city [EUR/m]	600	600	600	600
Conductor resistance [Ω/m]	0,000125	0,000053	0,0000192	0,000011711
Current rating [A]	390	670	1100	1400
Conductor max temperature [˚C]	65	65	65	65

Maintenance				
Maintenance cost - suburban [EUR/km,a]	1000	1000	1000	1000
Maintenance cost - city [EUR/km,a]	2000	2000	2000	2000



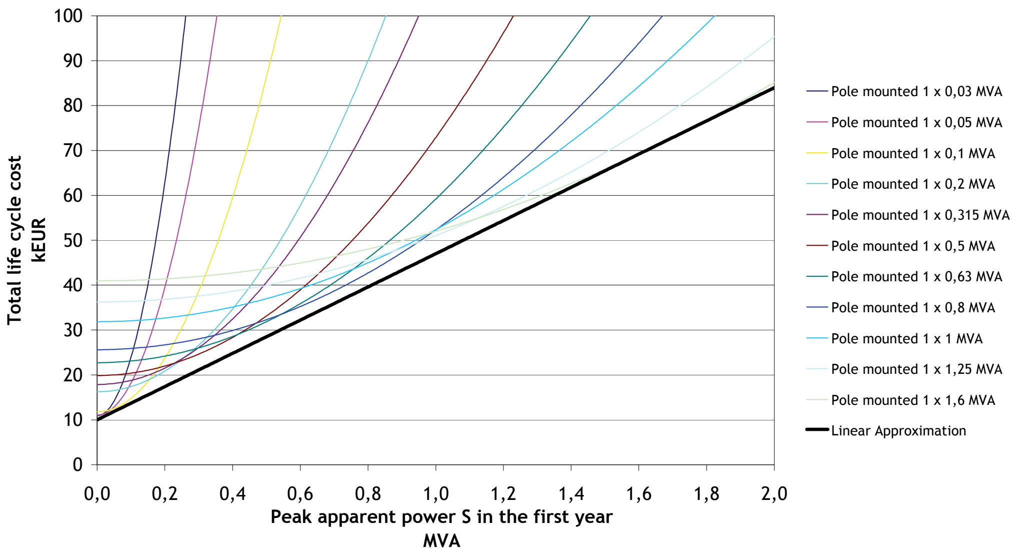
Area	f_1 **EUR/m**	f_2 **EUR/m**	f_3 **EUR/m**	f_{total} **EUR/m**	**v EUR·10^{-3}/A,m**
Suburban	9,0	120,0	251,0	380,0	330
City	9,0	120,0	571,0	700,0	330

Cost approximation = [$(f_1 + f_2 + f_3) + v \cdot 10^{-3} \cdot$Current/A]·Line length/m

Linear cost function approximation
- Transformer stations, pole-mounted

Interest rate [%]	6
Load growth rate [%/year]	0,12
Life cycle [years]	40
Time of load growth [years]	40
Peak utilization [h/year]	3500
cosφ	0,94
Price of power losses [EUR/kVA,year]	29,00
Price of no-load energy losses [EUR/kWh]	0,03
Price of load energy losses [EUR/kWh]	0,04
Discount factors	
- DF1 for constant annual cash flow (maintenance costs, no-load losses)	15,05
- DF2 for cost with quadrature relationship to the annual load growth (load losses)	15,54

	20/0,4 kV transformers											
	30 kVA	50 kVA	100 kVA	200 kVA	315 kVA	500 kVA	630 kVA	800 kVA	1000 kVA	1250 kVA	1600 kVA	
Investment												
- transformer	2,61	2,61	2,98	3,78	4,60	6,07	8,20	9,76	12,18	15,92	19,57	kEUR/unit
- 20 kV line disconnector	3,0	3,0	3,0	3,0	3,0	3,0	3,0	3,0	3,0	3,0	3,0	kEUR/station
- 20 kV RMU unit	-	-	-	-	-	-	-	-	-	-	-	kEUR/station
- 0,4 kv feeder connection	-	-	-	-	-	-	-	-	-	-	-	kEUR/station
- transformer station construction	3,8	3,8	3,8	6,6	6,6	6,6	6,6	6,6	9,3	9,3	9,3	kEUR/station
Investment total	9,4	9,4	9,8	13,4	14,2	15,7	17,8	19,3	24,5	28,2	31,9	kEUR/unit
Maintenance	70	70	70	70	70	70	70	70	70	70	70	EUR/station,year
Losses												
- nominal no-load losses P_0	0,10	0,14	0,22	0,42	0,60	0,72	0,89	1,20	1,45	1,60	1,84	kW
- nominal load losses P_k	0,59	0,89	1,49	2,30	4,50	6,60	7,20	8,50	10,20	11,50	14,10	kW
- price of no-load losses H_{Po}	290	290	290	290	290	290	290	290	290	290	290	EUR/kW,year
- price of load losses H_{Pk}	103	103	103	103	103	103	103	103	103	103	103	EUR/kW,year
- $P_0 \cdot H_{Po} \cdot DF_1$	0,45	0,61	0,96	1,83	2,62	3,14	3,88	5,24	6,33	6,98	8,03	kEUR/unit
- $P_k \cdot H_{Pk} \cdot DF_2$	0,93	1,41	2,37	3,66	7,19	10,54	11,50	13,57	16,29	18,36	22,51	kEUR/unit
Total life cycle cost												
- Fixed cost	10,9	11,1	11,8	16,2	17,9	19,9	22,7	25,6	31,9	36,3	41,0	kEUR/station
- Cost dependent on the peak load in the first year	0,93	1,41	2,37	3,66	7,19	10,54	11,50	13,57	16,29	18,36	22,51	$kEUR/unit/(S/S_N)^2$



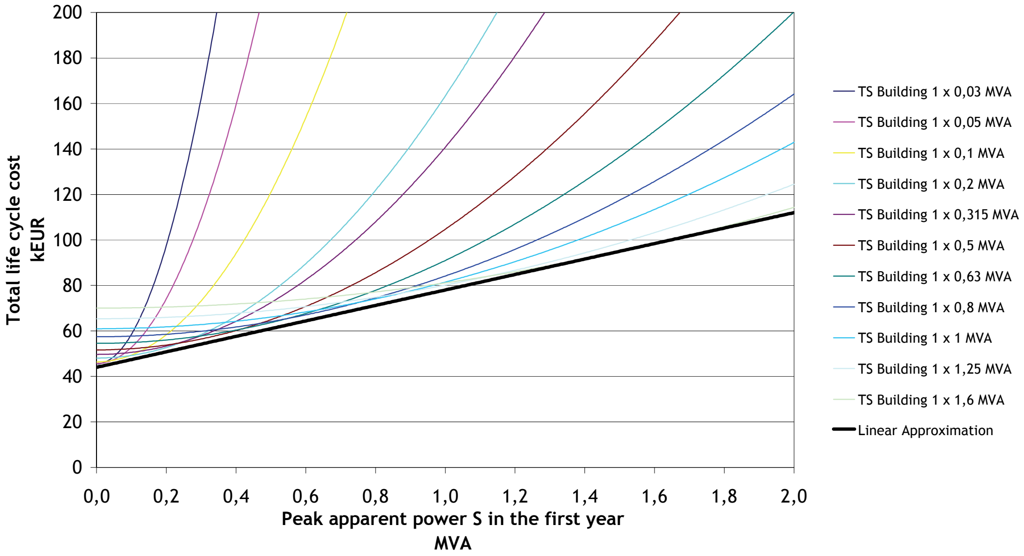
Area	f_1 kEUR	f_2 kEUR	f_3 kEUR	f_{total} kEUR	v kEUR/MVA
All	6,0	0,0	4,0	10,0	37

Cost approximation = $(f_1 + f_2 + f_3) + v \cdot$ Apparent power/MVA

Linear cost function approximation - Transformer stations in buildings

Interest rate [%]	6
Load growth rate [%/year]	0,12
Life cycle [years]	40
Time of load growth [years]	40
Peak utilization [h/year]	3500
cosφ	0,94
Price of power losses [EUR/kVA,year]	29,00
Price of no-load energy losses [EUR/kWh]	0,03
Price of load energy losses [EUR/kWh]	0,04
Discount factors	
- DF1 for constant annual cash flow (maintenance costs, no-load losses)	15,05
- DF2 for cost with quadrature relationship to the annual load growth (load losses)	15,54

	20/0,4 kV transformers											
	30 kVA	50 kVA	100 kVA	200 kVA	315 kVA	500 kVA	630 kVA	800 kVA	1000 kVA	1250 kVA	1600 kVA	
Investment												
- transformer	2,61	2,61	2,98	3,78	4,60	6,07	8,20	9,76	12,18	15,92	19,57	kEUR/unit
- 20 kV line disconnector	-	-	-	-	-	-	-	-	-	-	-	kEUR/station
- 20 kV RMU unit	5,5	5,5	5,5	5,5	5,5	5,5	5,5	5,5	5,5	5,5	5,5	kEUR/station
- 0,4 kV feeder connection	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	kEUR/station
- transformer station construction	30	30	30	30	30	30	30	30	30	30	30	kEUR/station
Investment total	43,1	43,1	43,5	44,3	45,1	46,6	48,7	50,3	52,7	56,4	60,1	kEUR/unit
Maintenance	130	130	130	130	130	130	130	130	130	130	130	EUR/station,year
Losses												
- nominal no-load losses P_0	0,10	0,14	0,22	0,42	0,60	0,72	0,89	1,20	1,45	1,60	1,84	kW
- nominal load losses P_k	0,59	0,89	1,49	2,30	4,50	6,60	7,20	8,50	10,20	11,50	14,10	kW
- price of no-load losses H_{Po}	290	290	290	290	290	290	290	290	290	290	290	EUR/kW,year
- price of load losses H_{Pk}	103	103	103	103	103	103	103	103	103	103	103	EUR/kW,year
- $P_0 \cdot H_{Po} \cdot DF_1$	0,45	0,61	0,96	1,83	2,62	3,14	3,88	5,24	6,33	6,98	8,03	kEUR/unit
- $P_k \cdot H_{Pk} \cdot DF_2$	0,93	1,41	2,37	3,66	7,19	10,54	11,50	13,57	16,29	18,36	22,51	kEUR/unit
Total life cycle cost												
- Fixed cost	45,5	45,7	46,4	48,1	49,7	51,7	54,5	57,5	61,0	65,4	70,1	kEUR/station
- Cost dependent on the peak load in the first year	0,93	1,41	2,37	3,66	7,19	10,54	11,50	13,57	16,29	18,36	22,51	kEUR/unit/$(S/S_N)^2$



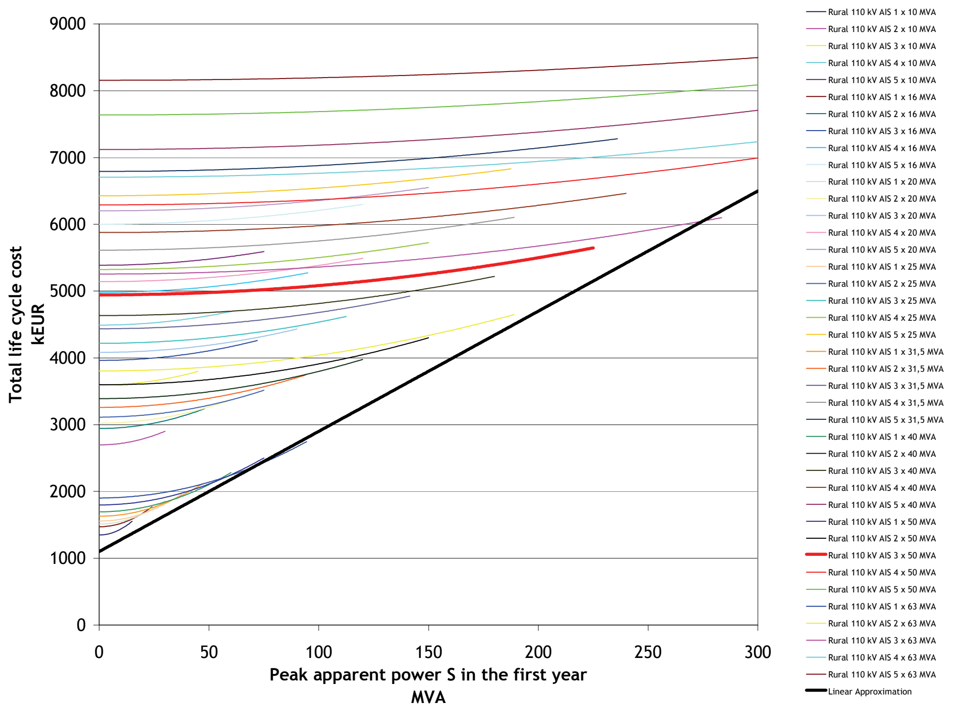
Area	f_1 kEUR	f_2 kEUR	f_3 kEUR	f_{total} kEUR	v kEUR/MVA
All	6,0	7,0	31,0	44,0	34

Cost approximation = $(f_1 + f_2 + f_3) + v \cdot$ Apparent power/MVA

Linear cost function approximation - Substations, Rural 110 kV AIS

Interest rate [%]	6
Load growth rate [%/year]	0,12
Life cycle [years]	40
Time of load growth [years]	40
Peak utilization [h/year]	4500
cosφ	0,94
Price of power losses [EUR/kVA,year]	5,00
Price of no-load energy losses [EUR/kWh]	0,03
Price of load energy losses [EUR/kWh]	0,04
Discount factors	
- DF1 for constant annual cash flow (maintenance costs, no-load losses)	15,05
- DF2 for cost with quadrature relationship to the annual load growth (load losses)	15,54

		110 kV switchgear (unit = bay)	110/20 kV transformer 10 MVA	16 MVA	20 MVA	25 MVA	31,5 MVA	40 MVA	50 MVA	63 MVA	20 kV switchgear (unit = bay)
Investment											
- primary equipment	kEUR/unit	300	177	284	305	327	382	425	507	583	38
- secondary and auxiliary equipment	kEUR/unit	77	32	32	32	32	32	32	32	32	22
- building											
- floor space required	m^2/unit	19	50	60	70	80	90	90	100	110	30
- floor space unit price	EUR/m^2	1000	800	800	800	800	800	800	800	800	1000
- cost per primary unit	kEUR/unit	19	40,0	48,0	56,0	64,0	72,0	72,0	80,0	88,0	30
- land											
- lot space required	m^2/unit	1500	250	250	250	250	250	250	250	250	70
- lot space unit price	EUR/m^2	2	2	2	2	2	2	2	2	2	2
- cost per primary unit	kEUR/unit	3	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,14
Investment total	kEUR/unit	399	249	364	394	424	486	530	619	703	90
Maintenance											
- primary equipment	EUR/unit,year	1500	2500	2500	2500	3000	3000	3000	3000	3000	200
- secondary and auxiliary equipment	EUR/unit,year	1700	560	560	560	560	560	560	560	560	500
- building	EUR/unit,year	300	500	500	500	500	500	500	500	500	360
- land	EUR/unit,year	-	-	-	-	-	-	-	-	-	-
Maintenance total	EUR/unit,year	3500	3560	3560	3560	4060	4060	4060	4060	4060	1060
Losses											
- nominal no-load losses P_0	kW		9,0	11,0	13,5	15,5	18,0	23,5	27,0	32,0	
- nominal load losses P_k	kW		51	74	87	100	122	146	175	210	
- price of no-load losses H_{P0}	EUR/kW,year		268	268	268	268	268	268	268	268	
- price of load losses H_{Pk}	EUR/kW,year		115	115	115	115	115	115	115	115	
- $P_0 \cdot H_{P0} \cdot DF_1$	kEUR/unit		36,2	44,3	54,3	62,4	72,4	94,6	108,7	128,8	
- $P_k \cdot H_{Pk} \cdot DF_2$	kEUR/unit		91,1	132,2	155,4	178,6	217,9	260,8	312,6	375,1	
Total life cycle cost											
- Dependent on the number of units	kEUR/unit	452	339	462	502	547	620	686	789	893	106
- Dependent on the 1. year peak load	kEUR/unit/$(S/S_N)^2$		91	132	155	179	218	261	313	375	



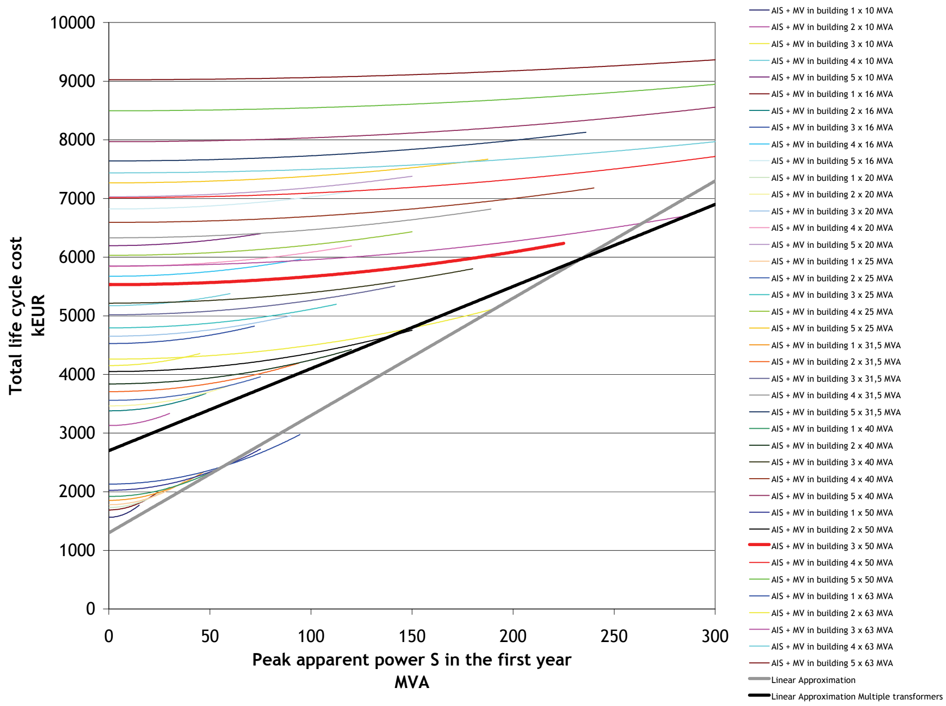
Area	f_1 kEUR	f_2 kEUR	f_3 kEUR	f_{total} kEUR	v kEUR/MVA
All	960	0	140	1100	18

Cost approximation = $(f_1 + f_2 + f_3) + v \cdot$ Apparent power/MVA

Linear cost function approximation - Substations, Suburban 110 kV AIS

Interest rate [%]	6
Load growth rate [%/year]	0,12
Life cycle [years]	40
Time of load growth [years]	40
Peak utilization [h/year]	4500
cosφ	0,94
Price of power losses [EUR/kVA,year]	5,00
Price of no-load energy losses [EUR/kWh]	0,03
Price of load energy losses [EUR/kWh]	0,04
Discount factors	
- DF1 for constant annual cash flow (maintenance costs, no-load losses)	15,05
- DF2 for cost with quadrature relationship to the annual load growth (load losses)	15,54

		110 kV switchgear (unit = bay)	110/20 kV transformer 10 MVA	16 MVA	20 MVA	25 MVA	31,5 MVA	40 MVA	50 MVA	63 MVA	20 kV switchgear (unit = bay)
Investment											
- primary equipment	kEUR/unit	300	177	284	305	327	382	425	507	583	38
- secondary and auxiliary equipment	kEUR/unit	77	32	32	32	32	32	32	32	32	22
- building											
- floor space required	m^2/unit	19	50	60	70	80	90	90	100	110	30
- floor space unit price	EUR/m^2	1200	1000	1000	1000	1000	1000	1000	1000	1000	1200
- cost per primary unit	kEUR/unit	23	50,0	60,0	70,0	80,0	90,0	90,0	100,0	110,0	36
- land											
- lot space required	m^2/unit	1500	250	250	250	250	250	250	250	250	70
- lot space unit price	EUR/m^2	60	60	60	60	60	60	60	60	60	60
- cost per primary unit	kEUR/unit	90	15	15	15	15	15	15	15	15	4,2
Investment total	kEUR/unit	490	274	391	422	454	519	562	654	740	100
Maintenance											
- primary equipment	EUR/unit,year	1500	2500	2500	2500	3000	3000	3000	3000	3000	200
- secondary and auxiliary equipment	EUR/unit,year	1700	560	560	560	560	560	560	560	560	500
- building	EUR/unit,year	300	500	500	500	500	500	500	500	500	360
- land	EUR/unit,year	-	-	-	-	-	-	-	-	-	-
Maintenance total	EUR/unit,year	3500	3560	3560	3560	4060	4060	4060	4060	4060	1060
Losses											
- nominal no-load losses P_0	kW		9,0	11,0	13,5	15,5	18,0	23,5	27,0	32,0	
- nominal load losses P_k	kW		51	74	87	100	122	146	175	210	
- price of no-load losses H_{Po}	EUR/kW,year		268	268	268	268	268	268	268	268	
- price of load losses H_{Pk}	EUR/kW,year		115	115	115	115	115	115	115	115	
- $P_0 \cdot H_{Po} \cdot DF_1$	kEUR/unit		36,2	44,3	54,3	62,4	72,4	94,6	108,7	128,8	
- $P_k \cdot H_{Pk} \cdot DF_2$	kEUR/unit		91,1	132,2	155,4	178,6	217,9	260,8	312,6	375,1	
Total life cycle cost											
- Dependent on the number of units	kEUR/unit	542	364	488	530	578	652	718	824	929	116
- Dependent on the 1. year peak load	kEUR/unit/$(S/S_N)^2$		91	132	155	179	218	261	313	375	



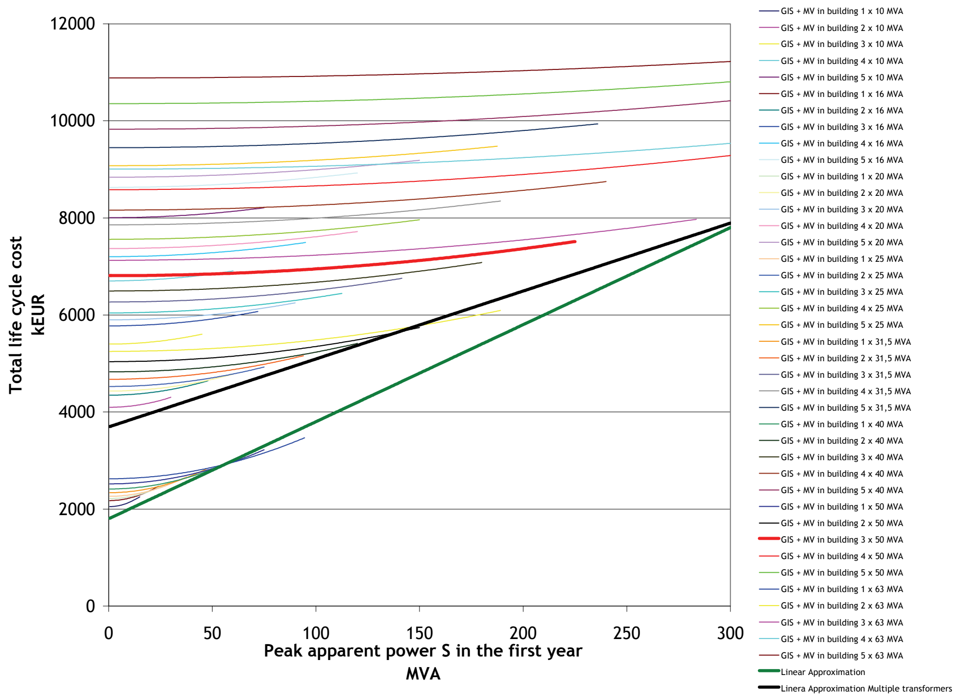
Area	f_1 kEUR	f_2 kEUR	f_3 kEUR	f_{total} kEUR	v kEUR/MVA
Suburban	960	0	340	1300	20
Suburban - multiple transformers	2100	0	600	2700	14

Cost approximation = $(f_1 + f_2 + f_3) + v \cdot$ Apparent power/MVA

Linear cost function approximation
- Substations, Suburban - Urban110 kV GIS, ground level building

Interest rate [%]	6
Load growth rate [%/year]	0,12
Life cycle [years]	40
Time of load growth [years]	40
Peak utilization [h/year]	4500
cosφ	0,94
Price of power losses [EUR/kVA,year]	5,00
Price of no-load energy losses [EUR/kWh]	0,03
Price of load energy losses [EUR/kWh]	0,04
Discount factors	
- DF1 for constant annual cash flow (maintenance costs, no-load losses)	15,05
- DF2 for cost with quadrature relationship to the annual load growth (load losses)	15,54

		110 kV switchgear (unit = bay)	110/20 kV transformer 10 MVA	16 MVA	20 MVA	25 MVA	31,5 MVA	40 MVA	50 MVA	63 MVA	20 kV switchgear (unit = bay)
Investment											
- primary equipment	kEUR/unit	454	177	284	305	327	382	425	507	583	38
- secondary and auxiliary equipment	kEUR/unit	77	32	32	32	32	32	32	32	32	22
- building											
- floor space required	m^2/unit	76	70	80	90	100	110	120	130	140	30
- floor space unit price	EUR/m^2	1500	1000	1000	1000	1000	1000	1000	1000	1000	1500
- cost per primary unit	kEUR/unit	114	70,0	80,0	90,0	100,0	110,0	120,0	130,0	140,0	45
- land											
- lot space required	m^2/unit	192	250	250	250	250	250	250	250	250	70
- lot space unit price	EUR/m^2	200	200	200	200	200	200	200	200	200	200
- cost per primary unit	kEUR/unit	38,4	50	50	50	50	50	50	50	50	14
Investment total	kEUR/unit	683	329	446	477	509	574	627	719	805	119
Maintenance											
- primary equipment	EUR/unit,year	1500	2500	2500	2500	3000	3000	3000	3000	3000	200
- secondary and auxiliary equipment	EUR/unit,year	1700	560	560	560	560	560	560	560	560	500
- building	EUR/unit,year	1000	600	600	600	600	600	600	600	600	400
- land	EUR/unit,year	-	-	-	-	-	-	-	-	-	-
Maintenance total	EUR/unit,year	4200	3660	3660	3660	4160	4160	4160	4160	4160	1100
Losses											
- nominal no-load losses P_0	kW		9,0	11,0	13,5	15,5	18,0	23,5	27,0	32,0	
- nominal load losses P_k	kW		51	74	87	100	122	146	175	210	
- price of no-load losses H_{P0}	EUR/kW,year		268	268	268	268	268	268	268	268	
- price of load losses H_{Pk}	EUR/kW,year		115	115	115	115	115	115	115	115	
- $P_0 \cdot H_{P0} \cdot DF_1$	kEUR/unit		36,2	44,3	54,3	62,4	72,4	94,6	108,7	128,8	
- $P_k \cdot H_{Pk} \cdot DF_2$	kEUR/unit		91,1	132,2	155,4	178,6	217,9	260,8	312,6	375,1	
Total life cycle cost											
- Dependent on the number of units	kEUR/unit	747	420	545	587	634	709	785	890	996	136
- Dependent on the 1. year peak load	kEUR/unit/$(S/S_N)^2$		91	132	155	179	218	261	313	375	



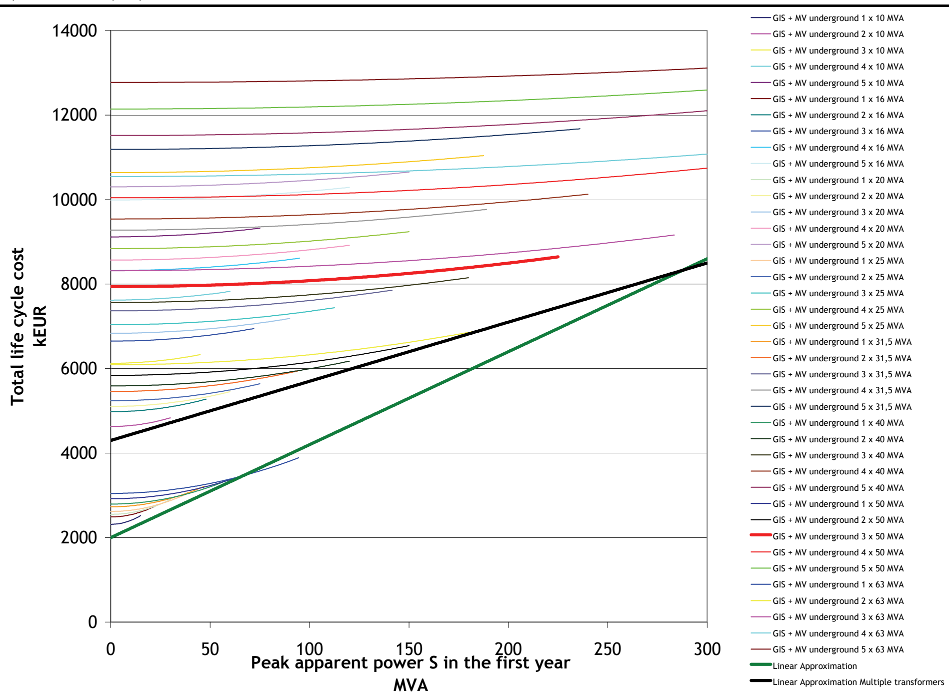
Area	f_1 kEUR	f_2 kEUR	f_3 kEUR	f_{total} kEUR	v kEUR/MVA
Suburban - Urban	960	310	530	1800	20
Suburban - Urban, Multiple transformers	2100	560	1040	3700	14

Cost approximation = $(f_1 + f_2 + f_3) + v \cdot$ Apparent power/MVA

Linear cost function approximation
- Substations, Urban110 kV GIS underground

Interest rate [%]	6
Load growth rate [%/year]	0,12
Life cycle [years]	40
Time of load growth [years]	40
Peak utilization [h/year]	4500
cosφ	0,94
Price of power losses [EUR/kVA,year]	5,00
Price of no-load energy losses [EUR/kWh]	0,03
Price of load energy losses [EUR/kWh]	0,04
Discount factors	
- DF1 for constant annual cash flow (maintenance costs, no-load losses)	15,05
- DF2 for cost with quadrature relationship to the annual load growth (load losses)	15,54

		110 kV switchgear (unit = bay)	110/20 kV transformer 10 MVA	16 MVA	20 MVA	25 MVA	31,5 MVA	40 MVA	50 MVA	63 MVA	20 kV switchgear (unit = bay)
Investment											
- primary equipment	kEUR/unit	454	177	284	305	327	382	425	507	583	38
- secondary and auxiliary equipment	kEUR/unit	77	32	32	32	32	32	32	32	32	22
- building											
- floor space required	m^2/unit	150	140	180	200	220	250	250	270	290	60
- floor space unit price	EUR/m^2	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500
- cost per primary unit	kEUR/unit	225	210,0	270,0	300,0	330,0	375,0	375,0	405,0	435,0	90
- land											
- lot space required	m^2/unit	0	0	0	0	0	0	0	0	0	0
- lot space unit price	EUR/m^2	0	0	0	0	0	0	0	0	0	0
- cost per primary unit	kEUR/unit	0	0	0	0	0	0	0	0	0	0
Investment total	kEUR/unit	756	419	586	637	689	789	832	944	1050	150
Maintenance											
- primary equipment	EUR/unit,year	1500	2500	2500	2500	3000	3000	3000	3000	3000	200
- secondary and auxiliary equipment	EUR/unit,year	1700	560	560	560	560	560	560	560	560	500
- building	EUR/unit,year	1000	600	600	600	600	600	600	600	600	400
- land	EUR/unit,year	-	-	-	-	-	-	-	-	-	-
Maintenance total	EUR/unit,year	4200	3660	3660	3660	4160	4160	4160	4160	4160	1100
Losses											
- nominal no-load losses P_0	kW		9,0	11,0	13,5	15,5	18,0	23,5	27,0	32,0	
- nominal load losses P_k	kW		51	74	87	100	122	146	175	210	
- price of no-load losses H_{P0}	EUR/kW,year		268	268	268	268	268	268	268	268	
- price of load losses H_{Pk}	EUR/kW,year		115	115	115	115	115	115	115	115	
- $P_0 \cdot H_{P0} \cdot DF_1$	kEUR/unit		36,2	44,3	54,3	62,4	72,4	94,6	108,7	128,8	
- $P_k \cdot H_{Pk} \cdot DF_2$	kEUR/unit		91,1	132,2	155,4	178,6	217,9	260,8	312,6	375,1	
Total life cycle cost											
- Dependent on the number of units	kEUR/unit	819	510	685	747	814	924	990	1115	1241	167
- Dependent on the 1. year peak load	kEUR/unit/$(S/S_N)^2$		91	132	155	179	218	261	313	375	



Area	f_1 kEUR	f_2 kEUR	f_3 kEUR	f_{total} kEUR	v kEUR/MVA
Urban - Urban core	960	310	730	2000	22
Urban - Urban core, Multiple transformers	2100	560	1640	4300	14

Cost approximation = $(f_1 + f_2 + f_3) + v \cdot$ Apparent power/MVA

Linear cost function approximation – Summary

Lines	f_1 EUR/m	f_2 EUR/m	f_3 EUR/m	f_{total} EUR/m	v EUR/m,A
0,4 kV twisted air cables	5,0		5,0	10,0	0,25
0,4 kV underground cables - rural	5,0	1,7	4,3	11,0	0,28
0,4 kV underground cables - urban	5,0	1,7	16,3	23,0	0,28
0,4 kV underground cables - city	5,0	1,7	28,3	35,0	0,28
20 kV overhead lines	6,0		9,0	15,0	0,25
20 kV underground cables - rural area	6,0	27,2	6,8	40,0	0,20
20 kV underground cables - urban	6,0	27,2	24,8	58,0	0,20
20 kV underground cables - city core	6,0	27,2	44,8	78,0	0,20
110 kV overhead lines - wooden poles	9,0		31,0	40,0	0,45
110 kV overhead lines - steel towers	9,0		111,0	120,0	0,33
110 kV cables - suburban	9,0	120,0	251,0	380,0	0,33
110 kV cables - city	9,0	120,0	571,0	700,0	0,33

Cost approximation = [$(f_1 + f_2 + f_3)$ + v·Peak current in the first year/A] · Line length/m

20/0,4 kV transformer stations	f_1 kEUR /station	f_2 kEUR /station	f_3 kEUR /station	f_{total} kEUR /station	v kEUR /station,MVA
20/0,4 kV transformer station - pole mounted	6		4	10	37
20/0,4 kV transformer station - in a building	6	7	31	44	34

Cost approximation = $(f_1 + f_2 + f_3)$ + v·Peak apparent power in the first year/MVA

110/20 kV substations	f_1 kEUR /station	f_2 kEUR /station	f_3 kEUR /station	f_{total} kEUR /station	v kEUR /station,MVA
110 kV AIS - rural	960		140	1100	18
110 kV AIS - suburban, single transformer	960		340	1300	20
110 kV GIS - suburban - urban, single transformer	960	310	530	1800	20
110 kV GIS - urban - urban core, single transformer	960	310	730	2000	22
110 kV AIS - suburban, multiple transformers	2100		600	2700	14
110 kV GIS - suburban - urban, ground level building, multiple transf.	2100	560	1040	3700	14
110 kV GIS - urban core, underground, multiple transformers	2100	560	1640	4300	14

Cost approximation = $(f_1 + f_2 + f_3)$ + v·Peak apparent power in the first year/MVA

20 kV feeder bays at substations	f_1 kEUR /feeder	f_2 kEUR /feeder	f_3 kEUR /feeder	f_{total} kEUR /feeder
110/20 kV substation - 20 kV enclosed switchgear indoors rural	71		36	107
110/20 kV substation - 20 kV enclosed switchgear indoors suburban	71		46	117
110/20 kV substation - 20 kV enclosed switchgear indoors urban	71		65	136
110/20 kV substation - 20 kV enclosed switchgear indoors underground	71		96	167

Cost approximation = $(f_1 + f_2 + f_3)$ · Number of MV feeders

Evaluation parameters and technical constraints

Interest rate	6%
Load growth	0,12%/year
Load growth period	40 years
Life cycle	40 years
DF_1	15,05 (discount factor when the annual cash flow is constant)
DF_2	15,54 (discount factor when costs have quadrature relationship to the annual load growth)
DF_3	15,29 (discount factor when the load and costs increase by a fixed percentage each year)
$\cos\varphi$	0,94
L_{CP}	20 m
Peak utilization T_p	3000 h/a (LV lines), typical value used in the linear approximations 3500 h/a (MV/LV stations), “ 4000 h/a (MV lines), “ 4500 h/a (HV/MV stations), “ 5000 h/a (HV lines), “
Price of power losses h_{pl}	80 €/kVA,a (LV line losses), marginal capacity investment cost 29 €/kVA,a (MV/LV transformer losses), “ 25 €/kVA,a (MV line losses), “ 5 €/kVA,a (HV/MV transformer and HV line losses), “
Price of energy losses	h_{w0} = 0,03 €/kWh (no-load losses) h_{wk} = 0,04 €/kWh (load losses)

Price of transformer losses [€/kW,a]

$$h_{p0} = \cos\varphi \cdot h_{pl} + 8760h/a \cdot h_{w0}$$
$$h_{pk} = \cos\varphi \cdot h_{pl} + 8760h/a \cdot (\eta^3 - \eta^{2,5} + \eta^{1,5}) \cdot h_{wk}\text{ , where } \eta = T_p/8760h$$

Nominal voltages	0,4 kV (LV)	20 kV (MV)	110 kV (HV)

	LV feeders	MV feeders
v_{dmax}	6%	4%
I_{kmin}	3x315A underground cables 3x160A twisted aerial cables	$1{,}5xI_{LoadMax}$
S_{max}	(see Appendix 4)	4 MVA

	MV/LV stations	HV/MV stations	EHV/HV stations
S_{max} (load)	2/3 x 1 MVA urban 1 MVA industrial 0,5 MVA rural	2/3 x160 MVA	2/3 x (2x400 MVA)
u_k	5%	12%	
$N_{Feeder,min}$	-	4 urban / 3 rural	
$N_{Feeder,max}$	16 urban / 8 rural	50 urban / 20 rural	
$I_{dyn,max}$	125 kA urban / 50 kA rural	100 kA	

Summary of the fault statistics

	Overhead lines	Covered conductors	Aerial cables	Underground cables	Total	Lines in forest	Number of MV/LV stations	Number of HV/MV stations	Number of customers	Annual energy	Lines with automatic reclosure	Faults cleared by RAR	Faults cleared by DAR	Sustained faults	Planned Outages
Database networks	(km)	(km)	(km)	(km)	(km)				(meters)	(MWh)	(km)	(/100 km,a)	(/100 km,a)	(/100 km,a)	(/100 km,a)
Rural	102 742	6 178	259	2 125	111 304	50 %			1 242 904	17 299 356	89 191	24,59	9,63	8,19	8,07
Urban	4 970	776	245	2 687	8 678	32 %			371 474	6 077 987	2 944	12,18	4,62	6,95	10,25
City	624	123	52	6 611	7 410	19 %			1 090 173	15 909 058	2 085	1,29	0,39	3,35	6,77
Total	108 336	7 077	556	11 423	127 392	56 %	125 158	592	2 704 551	39 286 401	94 220	25,91	11,04	7,78	7,86
Neutral treatment	(km)	(km)	(km)	(km)	(km)						(km)	(/100 km,a)	(/100 km,a)		
Isolated neutral	65 342	4 079	302	7 769	77 492						61 829	19,88	9,74		
Partially compensated	2 262	103	2	157	2 524						2 353	18,06	6,75		
Resonant earthed	42 179	2 975	200	4 113	49 467						30 614	13,53	6,03		
Total	109 783	7 157	504	12 039	129 483						94 796	16,94	6,84		
Component failure rates	(/100 km,a)	(/100 km,a)	(/100 km,a)	(/100 km,a)			(/100 stations,a)	(/station,a)							
Wind and storm	2,24	0,22	0,07	0,01			0,12	0,05							
Snow and ice load	2,10	0,05	0,00	0,01			0,02	0,04							
Thunder	0,37	0,01	0,02	0,01			0,13	0,05							
Other weather	0,13	0,04	0,00	0,00			0,03	0,03							
Animals	0,13	0,01	0,00	0,00			0,12	0,02							
Natural phenomena total	**4,70**	**0,25**	**0,06**	**0,02**			**0,32**	**0,08**							
Equipment failure	0,45	0,08	0,02	0,24			0,19	0,09							
Operational	0,22	0,01	0,02	0,11			0,08	0,10							
Technical total	**0,63**	**0,09**	**0,03**	**0,31**			**0,26**	**0,16**							
External	0,37	0,00	0,23	0,30			0,05	0,02							
Unknown	0,77	0,03	0,01	0,10			0,10	0,10							
Force major	0,00	0,11	0,00	0,00			0,00	0,00							
Other total	**1,07**	**0,04**	**0,05**	**0,33**			**0,12**	**0,11**							
Unplanned outages	**6,29**	**0,31**	**0,10**	**0,60**			**1,02**	**0,30**							
Planned outages	**2,38**	**0,42**	**0,29**	**0,43**			**1,42**	**0,12**							
Total	**7,76**	**0,40**	**0,19**	**0,71**			**1,02**	**0,33**							

Source: Interruption statistics 2006, Finnish Energy Industries

Reliability evaluation – Cost parameters

	Unit	Investment cost EUR/unit	Yearly costs EUR/unit,a	Annualized cost EUR/unit,a
Repair costs				
- overhead line faults	1 200 EUR/fault			
- cable faults	3 000 EUR/fault			
Mitigation costs				
Switches and network automation				
- manually controlled line disconnector	pc	3 000	75	274
- remotely controlled disconnector station, 1 disc. incl. SCADA connection	pc	14 500	145	1109
- remotely read fault indicators and transformer station supervision	pc	-	-	550
- remotely controlled RMU disconnectors, additional cost	pc	-	-	1000
- network circuit breaker	pc	30 000	300	2294
- network circuit breaker station (3 cbs and 3 disconnectors in a building)	pc	68 000	680	5199
Line investments				
- overhead lines	km	18 000	120	1316
- cables	km	40 000	50	2708
Earth-fault compensation, cost per km of cable lines	km	3 100	27	233 *)

Customer interruption costs

User group	EUR/kW	EUR/kWh
- domestic	0,36	4,29
- agricultural	0,45	9,38
- industry	3,52	24,45
- public services	1,89	15,08
- commercial	2,65	29,89

*) Estimation of earth-fault current compensation cost per kilometer of cable line:

		400 A unit in urban substation	100 A unit in rural substation	
Investment				
- compensation equipment installed	EUR/pc	120 000	65 000	
- space requirement, building				
- floor space	m^2/pc	40	-	
- unit price	EUR/m^2	1 500	-	
- building cost	EUR/pc	60 000	-	
- space requirement, land				
- lot space	m^2/pc	40	35	
- unit price	EUR/m^2	200	2	
- building cost	EUR/pc	8 000	70	
- medium voltage switchgear bay total cost	EUR/bay	150 000	90 000	
Investment total	EUR/pc	338 000	155 070	
Investment total per A	EUR/A	845	1 551	
Maintenance				
- compensation equipment 1,5% per year	EUR/pc,a	1 000	500	
- building	EUR/m^2,a	10	-	
- medium voltage switchgear bay	EUR/pc,a	1 100	1 060	
Maintenance total	EUR/pc,a	2 500	1 560	
Maintenance total per A	EUR/A,a	6	16	
Earth-fault current per kilometer of cable		3,5	2,1	
Total cost per kilometer				→ Average values:
- investment	EUR/km	2 958	3 256	3 107
- maintenance	EUR/km,a	21,9	32,8	27

Sources of data:
- Unit prices for the components in electricity distribution networks for the year 2007, the Finnish Energy Market Authority
- Helen Electricity Ltd, estimates based on budgetary offers
- Lohjala J, Development of rural area electricity distribution system - potentiality of using 1000 V supply system, Acta Universitatis Lappeenrantaensis 205, Dissertation, Lappeenranta University of Technology, 2005
- Bertling L, Reliability Centred Maintenance for Electric Power Distribution Systems, Doctoral Thesis, Royal Institute of Technology (KTH), 2002
- Silvast et al, Outage costs in electrical distribution networks, Helsinki University of Technology, Tampere University of Technology, December 2005

Reference substation service area data – Table of indicators

	U11 Urban core	U12 Urban Industrial	U13 Urban mixed	U14 Suburban Industrial	U15 Suburban small house - mixed	U16 Suburban apart.blocks - mixed	U17 Suburban small house - mixed	U21 Urban Suburban	R21 Suburban - rural	R22 Rural	R23 Rural
Substation service area (km2)	1,26	2,43	4,15	3,85	13,32	14,60	25,17	12,25	2450	1925	2576
Share of open space	0 %	0 %	0 %	0 %	0 %	0 %	0 %	0 %	69 %	74 %	85 %
Area efficiency e	1,86	0,65	0,78	0,38	0,19	0,19	0,11	NA	NA	NA	NA
Annual energy (GWh/a)	290,8	186,5	200,8	183,5	206,1	237,9	244,6	110,3	75,1	27,7	8,3
Substation peak load (MW)	52,7	36,5	41,9	37,2	48,5	49,9	54,9	23,3	26,0	8,8	3,6
MV load density (MWh/km2)	41,8	15,0	10,1	9,7	3,6	3,4	2,2	1,9	0,011	0,0046	0,0014
Energy density (GWh/km2)	231	76,7	48,4	47,6	15,5	16,3	9,7	9,0	0,031	0,014	0,0032
Peak utilization (h/a) med	5 523	5 103	4 788	4 926	4 250	4 765	4 458	4 729	4 114	3 154	2 284
Number of customers and connections											
Number of customers	11 328	7 809	33 341	6 805	20 911	28 482	23 579	6 687	7 205	2 704	850
Number of customers LV	11 206	7 758	33 304	6 761	20 894	28 463	23 565	6 677		2 704	850
Number of customers MV	122	51	37	44	12	19	14	10		0	0
Number of connections	404	336	919	307	4 280	2 290	4 371	1 244		1 504	825
Number of connections LV	336	287	884	269	4 266	2 271	4 357	1 234		1 504	825
Number of connections MV	68	49	35	38	12	19	14	10		0	0
Connection point density (/km²)											
LV	267	118	213	70	320	156	173	101	NA	0,78	0,32
MV/LV network stations	38	15	14	10	12	9	7	5,6	0,21	0,15	0,10
MV customers	62	22	9	10	0,9	2	0,7	1	NA	0	0
MV total	100	37	24	21	13	11	8	6,45	NA	0,15	0,10
Distance between connections (km)											
LV	0,061	0,092	0,068	0,120	0,056	0,080	0,076	0,100	NA	1,131	1,767
MV total	0,162	0,260	0,263	0,310	0,291	0,330	0,375	0,424	NA	2,559	3,191
	0,127										
Customer density (/km²)											
LV	8 898	3 192	8 032	1 754	1 569	1 950	936	545	NA	1,4	0,33
MV customers	97	21	8,9	11	0,9	1,3	0,6	0,8	NA	0	0
Total	8 995	3 213	8 041	1 765	1 569	1 951	937	546	2,9	1,4	0,33
Customers per connection											
LV	33,4	27,0	37,7	25,1	4,9	12,5	5,4	5	NA	1,8	1,0
MV/LV network stations	233	216	555	169	133	212	132	98	NA	9,2	3,4
MV customers	1,6	1,0	0,9	1,1	1,0	0,6	0,8	NR	NR	NR	NR
Population density (/km²)	10338	4181	10002	2966	3304	3599	1920	NA	NA	NA	NA
Customers per population	0,87	0,77	0,80	0,60	0,47	0,54	0,49	NA	NA	NA	NA
Line length (km/km²)											
LV	66,7	29,5	37,9	17,4	39,4	23,6	20,8	10,4	0,09	0,11	0,06
MV	38,9	19,0	13,9	8,8	8,8	7,0	5,5	3,4	0,27	0,22	0,16
Line per connection (m)											
LV	250	250	178	250	123	152	120	104	NA	139	175
MV total	389	518	580	424	693	626	707	520	NA	1416	1598
Line per customer (m)											
LV	7	9	5	10	25	12	22	19	NA	77	170
Total	12	15	6	15	31	16	28	25	121	231	646
Medium voltage	10 kV	10 kV	10 kV	20 kV	20 kV	20 kV	20 kV	20 kV	20 kV	20 kV	20 kV

Reference substation service area data – Network volume part 1

	U11 Urban core	U12 Urban Industrial	U13 Urban mixed	U14 Suburban Industrial	U15 Suburban small house - mixed	U16 Suburban apart.blocks - mixed	U17 Suburban small house - mixed	U21 Urban Suburban	R21 Suburban - rural	R22 Rural	R23 Rural
LV twisted aerial cables (m)											
Al 16-25	0	14	337	230	13 041	7 742	11 403	2 345	66 100	41 025	41 971
Al 35-50	0	0	22	0	2 442	898	2 015	1 550	200 900	80 828	68 606
Al 70	0	501	1 001	692	38 394	23 924	22 583	3 526	95 200	40 007	17 275
Al 120	0	0	0	0	59	0	0	0	26 400	2 743	3 802
Other	25	30	124	5	3 039	2 209	3 341	0	42 100	13 992	4 541
LV cables (m)											
Al 25 or smaller	10 745	7 376	18 215	2 564	81 124	34 779	84 205	26 660	75 500	6 377	2 475
Al 35-50	626	2 537	2 427	1 162	51 809	34 693	67 683	6 593	43 200	3 457	3 454
Al 70	1 342	2 245	6 088	1 841	12 774	8 930	20 111	12 970	3 100	171	0
Al 95-120	15 741	15 244	35 822	8 654	9 246	20 417	12 228	37 315	40 600	11 720	1 939
Al 150-185	55 506	42 815	93 294	52 009	312 575	210 475	299 618	30 037	35 200	8 105	0
Al 240-300	57	1 030	0	0	0	0	0	6 900	19 000	115	724
LV connection boxes											
Branch box	0	0	0	0	0	0	0	71	103	32	7
Connection box ≤ 400 A	0	0	0	0	0	0	0	88	150	90	5
Connection box ≥ 630 A	150	120	358	93	1008	532	970	131	77	2	0
Fuse switch ≤ 160 A	347	281	818	224	2496	1310	2401	0	1457	0	0
Fuse switch 250-400 A	1041	844	2455	671	7489	3930	7203	1784	827	661	31
Fuse switch 630 A	0	0	0	0	0	0	0	0	0	0	0
MV overhead lines (m)											
AlFe 34/6 or smaller	0	0	0	0	0	0	0	0	482 000	284 000	273 000
Al/Fe 54/9	0	0	0	0	0	0	0	0	111 000	87 000	128 000
Al/Fe 85/14	0	0	0	319	0	6 878	9 579	0	0	0	0
Al 132 or larger	0	0	0	0	0	0	0	1 500	14 500	36 200	2 700
Twisted aerial cable Al 70	0	0	0	0	0	0	0	0	3 500	0	0
Twisted aerial cable ≥ Al 120	0	0	0	0	0	0	0	0	0	0	0
Covered conductor Al 35-70	0	0	0	0	0	0	0	0	400	0	0
Covered conductor ≥ Al 95	0	0	0	0	0	0	0	1 900	24 200	0	0
MV cables (m)											
Al 70 or smaller	0	0	0	0	0	0	0	3 500	1 700	1 300	0
Al 95-120	2	170	403	992	1 645	11 080	175	7 800	3 200	1 000	200
Al 150-185	9 050	8 067	12 844	9 311	86 568	48 674	86 038	25 600	14 400	6 900	400
Al 240-300	39 985	37 888	44 214	23 314	28 964	36 036	42 828	800	2 200	0	0
MV switches											
Line disconnector, light	0	0	0	1	0	6	15	75	175	143	88
Line disconnector, gas chamber	0	0	0	0	0	0	0	215	259	129	0
Remote controlled, 1 disconnector	0	0	0	0	0	0	0	0	0	0	0
Remote controlled, 2 disconnectors	0	0	0	0	0	0	0	0	0	0	0
Remote controlled, 3-4 disconnectors	0	0	0	0	0	0	0	0	14	6	11
Transformer stations											
Pole-mounted, single pole	0	0	0	0	0	0	0	0	280	195	206
Pole-mounted, double pole	0	0	0	0	0	1	0	0	192	88	47
Pole-mounted, 4-pole	0	0	0	0	0	0	0	0	0	0	0
Separate house type 1	5	6	10	2	2	0	3	33	32	10	0
Separate house type 2	0	4	3	16	40	23	62	0	0	1	0
Transformer station in building	43	26	47	22	115	110	114	35	3	0	0
MV switching stations	4	2	0	0	0	2	1	0	0	0	0
MV customers' transformer stations	78	53	39	40	12	30	17	11	NA	0	0
MV/LV transformers											
16 kVA	0	0	0	0	0	0	0	0	111	111	131
30 kVA	0	0	0	0	0	0	0	0	142	91	80
50 kVA	0	0	0	0	0	0	0	0	120	41	24
100-160 kVA	0	0	0	0	0	0	0	1	62	16	10
200 kVA	0	0	0	0	0	0	0	0	24	15	7
300-315 kVA	0	0	1	1	6	3	7	5	19	12	0
500-630 kVA	18	24	38	20	87	91	89	39	20	6	0
800 kVA	19	12	17	11	47	29	60	21	11	1	0
1000 kVA	30	11	24	11	23	10	17	5	5	0	1
1250 kVA	2	1	1	0	1	1	5	0	0	0	0
1600 kVA	0	0	0	2	0	0	0	0	0	0	0

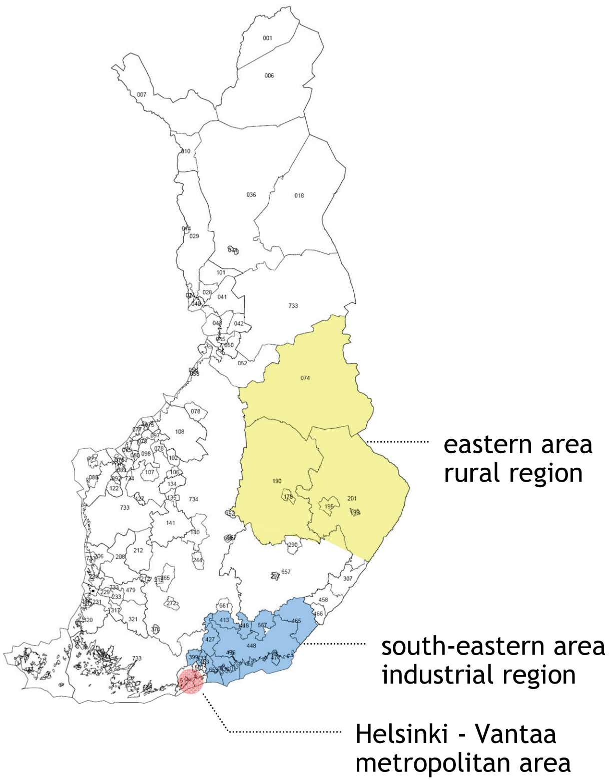
Reference substation service area data – Network volume part 2

	U11 Urban core	U12 Urban Industrial	U13 Urban mixed	U14 Suburban Industrial	U15 Suburban small house - mixed	U16 Suburban apart.blocks - mixed	U17 Suburban small house - mixed	U21 Urban Suburban	R21 Suburban - rural	R22 Rural	R23 Rural
Substation MV switchgear											
Number of MV circuit breaker bays	49	41	36	29	42	41	28	18		11	9
Number of MV feeders	42	34	29	25	35	30	21	13	22	7	4
Voltage	10 kV	10 kV	10 kV	20 kV	20 kV	20 kV	20 kV	20 kV	20 kV	20 kV	20 kV
Type	AIS	AIS	AIS	AIS	AIS	GIS	AIS	AIS	AIS	AIS	AIS
Busbar configuration	Duplex	Duplex	Duplex	Duplex	Duplex	Double	Duplex	Double	Single	Single	Single
HV/MV transformers											
6 MVA	0	0	0	0	0	0	0	0	0	0	1
10 MVA	0	0	0	0	0	0	0	0	0	0	0
16 MVA	0	0	0	0	0	0	0	0	0	1	0
20 MVA	0	0	0	0	0	0	0	1	0	0	0
25 MVA	0	0	0	0	0	0	0	1	1	0	0
31,5 MVA	2	2	2	1	0	0	0	0	0	0	0
40 MVA	0	0	0	1	3	2	2	0	0	0	0
110 kV switchgear											
Number of circuit breaker bays (distribution)	4	5	4	4	5	4	4	2	1	1	1
Type	GIS	GIS	GIS	GIS	GIS	AIS	AIS	AIS	AIS	AIS	AIS
	Underground	In building	In building	In building	In building	Open air	Open air	Open air	Open air	Open air	Open air
Substation building											
Floor area	2270	2796	2353	2865	1909	787	1175		~200		~200
Type	Underground rock cave	Building concrete + underground cave	Building concrete	Building concrete	Building concrete	Building concrete	Building concrete	Building concrete	NA NA	Building steel panel	Building steel panel
Lot area (m^2)	-	4033	2539	19308	8492	13600	22000	2911	3700	5525	4980

110 kV meshed transmission system reference areas

	Helsinki-Vantaa metropolitan area	south-eastern industrial regions	eastern rural area
Population ~	680 000	600 000	600 000
Area (km^2)	428	14 000	65 000
Equivalent diameter of the area (km)	23	134	288
Population density (inhabitants/km^2)	1 589	43	9
Peak demand ~ (MW)	1 060	1 000	1 000
Load density (MW/km^2)	2,477	0,071	0,015
Energy delivered to customers (GWh)	5 672	4 919	4 625
Energy density (GWh/km^2)	13,252	0,351	0,071
Distribution network customers	416 782	335 321	318 231
Customer density (customers/km^2)	974	24	5
Substations in total	28	75	87
Nodal substations in 110 kV transmission grid	14	11	13
Number of 110 kV lines outgoing from the nodes	71	70	66
110 kV overhead lines - wooden poles (%, estimate)	0 %	60 %	80 %
110 kV overhead lines - steel towers (%, estimate)	100 %	40 %	20 %
110 kV overhead lines - wooden poles (km)	0	1 040	1 436
110 kV overhead lines - steel towers (km)	257	116	160
110 kV bays AIS	41	70	66
110 kV bays GIS	30		
Average 110 kV transmission network cost (c/kWh)	0,19	0,13	0,14

Sources of data: Statistics Finland, Statistics by the Finnish Energy Market Authority, Map of the Finnish power grid



MV feeder system optimization algorithm ("VOH")

Description by John Millar and Matti Lehtonen, Helsinki University of Technology, 14.5.2008

1. Candidate network generation

An approximate power estimation and linear cost function are used to build up a radial network from the primary substation out to each load node (secondary substation). The full cost of the initial and all subsequent networks are calculated with accurate cost functions and load flows (and optimal placement of remote switching and reserve feeders to reduce outage costs, if these are required). The gradient of the linear cost function needed to generate the candidate network is adjusted to provide the cheapest candidate, and then the real power flow is fed back to the initial routine to further improve the candidate network.

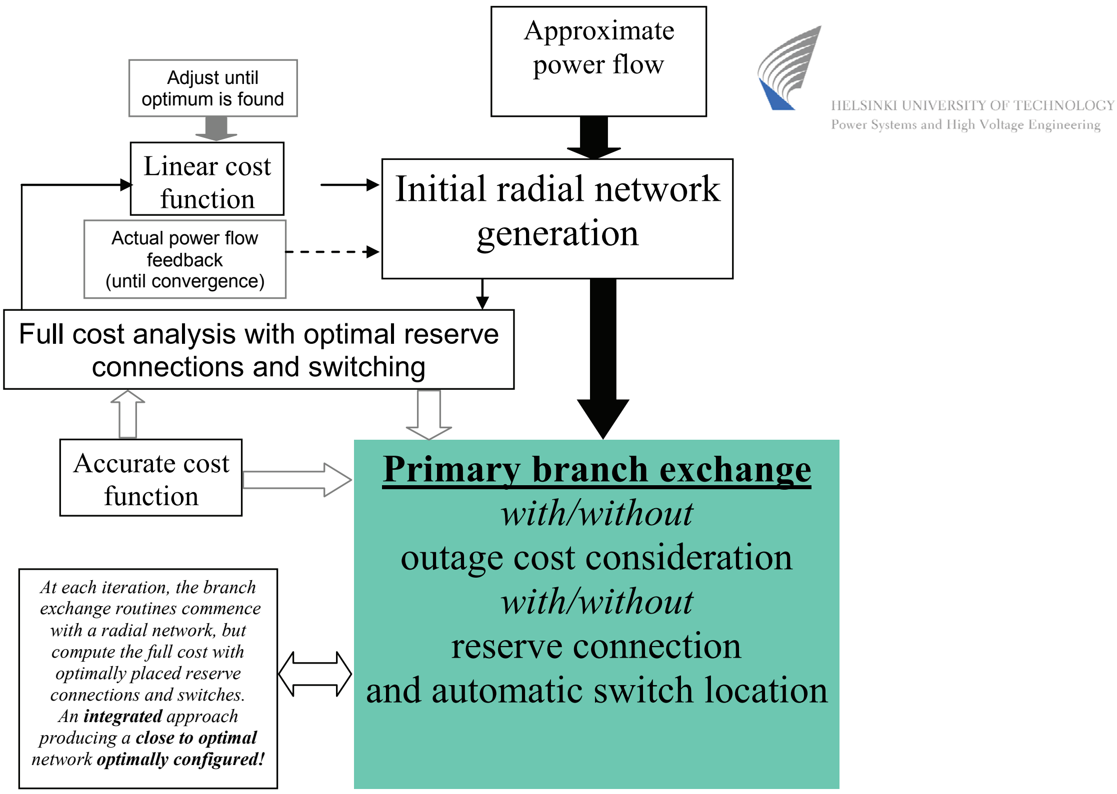
This produces a candidate network that is roughly appropriate to the loading and geographical layout of the network in question, with due consideration of the effect of outage costs if this is required.

2. The main algorithm

The candidate network is then modified by a complex but systematic series of branch exchanges. The branch exchange process essentially involves making a new connection, either downstream or to a node on another branch and then sequentially removing line sections to preserve radiality. Every time a change (which is first checked for feasibility) is attempted, its full cost implication is computed with the optimum placement of switches and reserve connections. If the change produces a cheaper network (including full line and installation costs, the cost of losses over a selected time period and the cost of outages), then the change is kept. Note that the starting point for each iteration is a purely radial network, without reserve connections and without any changes to switching – these are optimised in every iteration for each new radial network modification.

The basic algorithm should produce optimum backup (via reserve or cross connections) for nodes commensurate with the outage parameters and failure rates relevant to each load node and corresponding line section in the network. Full looping can be forced by setting the repair time parameter to an unreasonably high value, e.g., 100 times more than the nominal value(s). This forces the algorithm to eliminate repair time by making sure that every node has a backup supply. Reserve and cross connections are made assuming that there are manual disconnectors at the end of each line segment and then, if optimal switch placement is required, disconnectors that are not cost-effective are removed.

The algorithm is illustrated below.

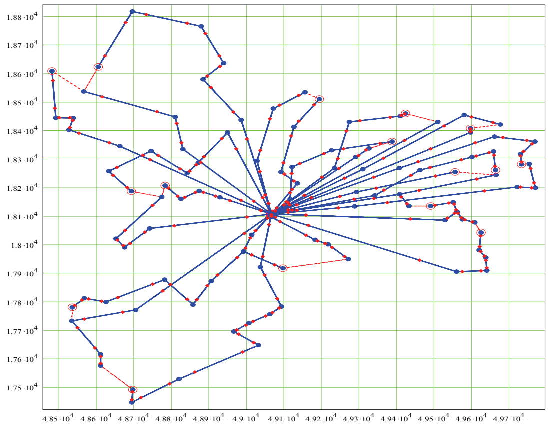


3. Parameters used in the algorithm

- Load growth per annum: 0.12%
- Interest rate: 6%
- Time period: 40 years
- Line voltage level: 10 kV or 20 kV
- Cost of energy losses: 0.04 €/kWh
- Hours per year of maximum loading for loss calculation: 3000 hours/annum
- Cost of new feeder connection to substation: 30000 €
- Length correction to direct internodal distances: 1.414
- Line type: underground cable, cost curves made up from Al70, 120 and 240 with city installation costs
- Outage frequency: 4 faults/100 km / year
- Outage cost per kW per fault: 1.1 € / kW / fault
- Outage cost per kWh per fault: 11 € / kW / hour
- Manual switching time: 0.5 h
- Repair time: 10 h global (1000 hours to force full looping)

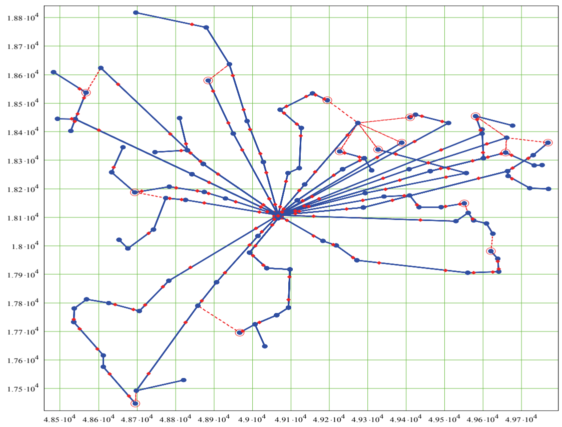
Reference area U11 fully looped 10 kV

Length of lines	23 622 m						
Length of reserve connections	1 700 m	Substation load		52 525 kVA			
Number of feeders	25	Feeder N:o	1	2 664 kVA	Feeder N:o	16	2 503 kVA
Number of remote disconnectors	0	Feeder N:o	2	1 597 kVA	Feeder N:o	17	1 976 kVA
Number of switching stations	0	Feeder N:o	3	2 811 kVA	Feeder N:o	18	1 349 kVA
		Feeder N:o	4	2 555 kVA	Feeder N:o	19	2 878 kVA
Looping ratio %	100 %	Feeder N:o	5	1 615 kVA	Feeder N:o	20	2 221 kVA
		Feeder N:o	6	3 740 kVA	Feeder N:o	21	1 858 kVA
Radial network cost	3 324 584 EUR	Feeder N:o	7	1 113 kVA	Feeder N:o	22	1 569 kVA
Full network cost	3 496 289 EUR	Feeder N:o	8	1 704 kVA	Feeder N:o	23	1 977 kVA
Reserve connections' cost	171 705 EUR	Feeder N:o	9	699 kVA	Feeder N:o	24	1 006 kVA
Conductor installed cost	1 003 656 EUR	Feeder N:o	10	2 182 kVA	Feeder N:o	25	2 161 kVA
Construction costs	1 375 491 EUR	Feeder N:o	11	2 571 kVA	Feeder N:o	26	kVA
Repair component of outage costs	0 EUR	Feeder N:o	12	3 319 kVA	Feeder N:o	27	kVA
Switching time component of outage costs	132 555 EUR	Feeder N:o	13	2 669 kVA	Feeder N:o	28	kVA
Manual disconnector investment savings	0 EUR	Feeder N:o	14	1 446 kVA	Feeder N:o	29	kVA
Total cost of network over 40 years	3 638 340 EUR	Feeder N:o	15	2 342 kVA	Feeder N:o	30	kVA



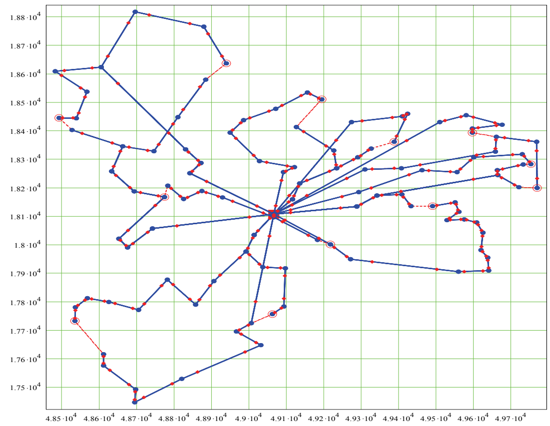
Reference area U11 optimally looped 10 kV

Length of lines	21 313 m						
Length of reserve connections	1 999 m	Substation load		52 525 kVA			
Number of feeders	22	Feeder N:o	1	2 861 kVA	Feeder N:o	16	1 936 kVA
Number of remote disconnectors	0	Feeder N:o	2	3 529 kVA	Feeder N:o	17	3 663 kVA
Number of switching stations	0	Feeder N:o	3	3 148 kVA	Feeder N:o	18	1 056 kVA
		Feeder N:o	4	1 391 kVA	Feeder N:o	19	3 019 kVA
Looping ratio %	79,4 %	Feeder N:o	5	2 959 kVA	Feeder N:o	20	2 234 kVA
		Feeder N:o	6	2 092 kVA	Feeder N:o	21	2 418 kVA
Radial network cost	3 007 446 EUR	Feeder N:o	7	2 974 kVA	Feeder N:o	22	1 744 kVA
Full network cost	3 210 190 EUR	Feeder N:o	8	2 170 kVA	Feeder N:o	23	kVA
Reserve connections' cost	202 744 EUR	Feeder N:o	9	3 025 kVA	Feeder N:o	24	kVA
Conductor installed cost	879 917 EUR	Feeder N:o	10	3 604 kVA	Feeder N:o	25	kVA
Construction costs	1 241 081 EUR	Feeder N:o	11	1 307 kVA	Feeder N:o	26	kVA
Repair component of outage costs	186 217 EUR	Feeder N:o	12	2 640 kVA	Feeder N:o	27	kVA
Switching time component of outage costs	129 864 EUR	Feeder N:o	13	789 kVA	Feeder N:o	28	kVA
Manual disconnector investment savings	228 000 EUR	Feeder N:o	14	2 110 kVA	Feeder N:o	29	kVA
Total cost of network over 40 years	3 307 794 EUR	Feeder N:o	15	1 856 kVA	Feeder N:o	30	kVA



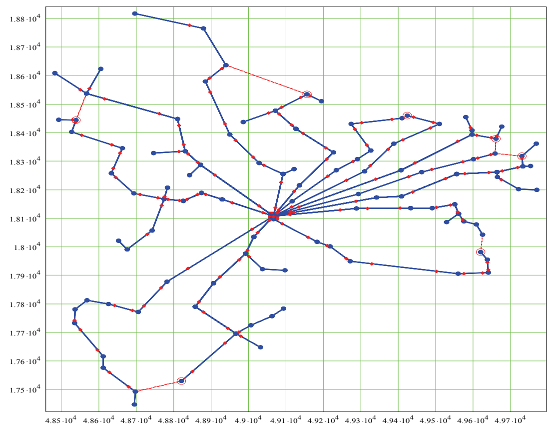
Reference area U11 fully looped 20 kV

Length of lines	17 326 m						
Length of reserve connections	1 124 m	Substation load		52 525 kVA			
Number of feeders	13	Feeder N:o	1	5 211 kVA	Feeder N:o	16	kVA
Number of remote disconnectors	0	Feeder N:o	2	4 349 kVA	Feeder N:o	17	kVA
Number of switching stations	0	Feeder N:o	3	2 971 kVA	Feeder N:o	18	kVA
		Feeder N:o	4	4 700 kVA	Feeder N:o	19	kVA
Looping ratio %	100 %	Feeder N:o	5	3 699 kVA	Feeder N:o	20	kVA
		Feeder N:o	6	2 926 kVA	Feeder N:o	21	kVA
Radial network cost	2 228 824 EUR	Feeder N:o	7	5 277 kVA	Feeder N:o	22	kVA
Full network cost	2 341 675 EUR	Feeder N:o	8	3 281 kVA	Feeder N:o	23	kVA
Reserve connections' cost	112 850 EUR	Feeder N:o	9	5 009 kVA	Feeder N:o	24	kVA
Conductor installed cost	730 155 EUR	Feeder N:o	10	3 955 kVA	Feeder N:o	25	kVA
Construction costs	1 008 904 EUR	Feeder N:o	11	2 586 kVA	Feeder N:o	26	kVA
Repair component of outage costs	0 EUR	Feeder N:o	12	3 692 kVA	Feeder N:o	27	kVA
Switching time component of outage costs	221 151 EUR	Feeder N:o	13	4 869 kVA	Feeder N:o	28	kVA
Manual disconnector investment savings	0 EUR	Feeder N:o	14	kVA	Feeder N:o	29	kVA
Total cost of network over 40 years	2 577 254 EUR	Feeder N:o	15	kVA	Feeder N:o	30	kVA



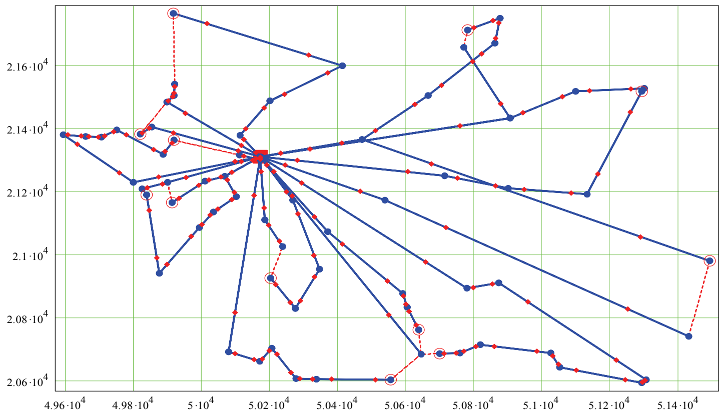
Reference area U11 optimally looped 20 kV

Length of lines	15 627 m						
Length of reserve connections	944 m	Substation load		52 525 kVA			
Number of feeders	13	Feeder N:o	1	3 802 kVA	Feeder N:o	16	kVA
Number of remote disconnectors	0	Feeder N:o	2	3 582 kVA	Feeder N:o	17	kVA
Number of switching stations	0	Feeder N:o	3	3 426 kVA	Feeder N:o	18	kVA
		Feeder N:o	4	3 021 kVA	Feeder N:o	19	kVA
Looping ratio %	72,0 %	Feeder N:o	5	7 032 kVA	Feeder N:o	20	kVA
		Feeder N:o	6	1 738 kVA	Feeder N:o	21	kVA
Radial network cost	2 022 052 EUR	Feeder N:o	7	4 922 kVA	Feeder N:o	22	kVA
Full network cost	2 115 389 EUR	Feeder N:o	8	4 761 kVA	Feeder N:o	23	kVA
Reserve connections' cost	93 338 EUR	Feeder N:o	9	4 682 kVA	Feeder N:o	24	kVA
Conductor installed cost	633 333 EUR	Feeder N:o	10	3 259 kVA	Feeder N:o	25	kVA
Construction costs	909 946 EUR	Feeder N:o	11	4 095 kVA	Feeder N:o	26	kVA
Repair component of outage costs	173 276 EUR	Feeder N:o	12	3 132 kVA	Feeder N:o	27	kVA
Switching time component of outage costs	192 323 EUR	Feeder N:o	13	5 072 kVA	Feeder N:o	28	kVA
Manual disconnector investment savings	243 000 EUR	Feeder N:o	14	kVA	Feeder N:o	29	kVA
Total cost of network over 40 years	2 250 305 EUR	Feeder N:o	15	kVA	Feeder N:o	30	kVA



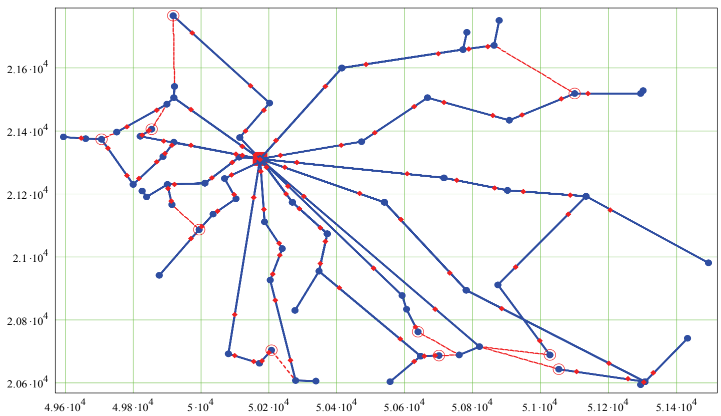
Reference area U12 fully looped 10 kV

Length of lines	22 670 m						
Length of reserve connections	1 869 m	Substation load		36 556 kVA			
Number of feeders	16	Feeder N:o	1	1 701 kVA	Feeder N:o	16	2 626 kVA
Number of remote disconnectors	0	Feeder N:o	2	3 878 kVA	Feeder N:o	17	kVA
Number of switching stations	0	Feeder N:o	3	311 kVA	Feeder N:o	18	kVA
		Feeder N:o	4	4 085 kVA	Feeder N:o	19	kVA
Looping ratio %	100 %	Feeder N:o	5	770 kVA	Feeder N:o	20	kVA
		Feeder N:o	6	1 194 kVA	Feeder N:o	21	kVA
Radial network cost	3 007 323 EUR	Feeder N:o	7	2 206 kVA	Feeder N:o	22	kVA
Full network cost	3 195 492 EUR	Feeder N:o	8	3 175 kVA	Feeder N:o	23	kVA
Reserve connections' cost	188 170 EUR	Feeder N:o	9	856 kVA	Feeder N:o	24	kVA
Conductor installed cost	934 323 EUR	Feeder N:o	10	3 237 kVA	Feeder N:o	25	kVA
Construction costs	1 320 095 EUR	Feeder N:o	11	737 kVA	Feeder N:o	26	kVA
Repair component of outage costs	0 EUR	Feeder N:o	12	3 674 kVA	Feeder N:o	27	kVA
Switching time component of outage costs	164 575 EUR	Feeder N:o	13	1 329 kVA	Feeder N:o	28	kVA
Manual disconnector investment savings	0 EUR	Feeder N:o	14	4 090 kVA	Feeder N:o	29	kVA
Total cost of network over 40 years	3 366 345 EUR	Feeder N:o	15	2 686 kVA	Feeder N:o	30	kVA



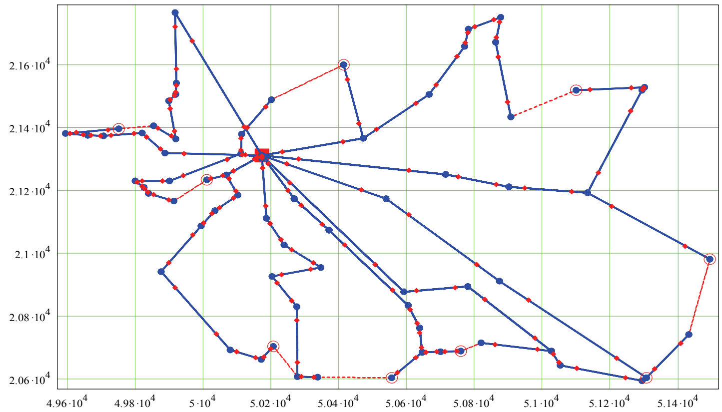
Reference area U12 optimally looped 10 kV

Length of lines	19 432 m						
Length of reserve connections	2 177 m	Substation load		36 556 kVA			
Number of feeders	15	Feeder N:o	1	2 537 kVA	Feeder N:o	16	kVA
Number of remote disconnectors	0	Feeder N:o	2	3 802 kVA	Feeder N:o	17	kVA
Number of switching stations	0	Feeder N:o	3	3 385 kVA	Feeder N:o	18	kVA
		Feeder N:o	4	2 728 kVA	Feeder N:o	19	kVA
Looping ratio %	78,6 %	Feeder N:o	5	2 498 kVA	Feeder N:o	20	kVA
		Feeder N:o	6	1 714 kVA	Feeder N:o	21	kVA
Radial network cost	2 599 083 EUR	Feeder N:o	7	1 642 kVA	Feeder N:o	22	kVA
Full network cost	2 817 043 EUR	Feeder N:o	8	1 563 kVA	Feeder N:o	23	kVA
Reserve connections' cost	217 959 EUR	Feeder N:o	9	1 026 kVA	Feeder N:o	24	kVA
Conductor installed cost	782 201 EUR	Feeder N:o	10	3 237 kVA	Feeder N:o	25	kVA
Construction costs	1 131 541 EUR	Feeder N:o	11	3 879 kVA	Feeder N:o	26	kVA
Repair component of outage costs	145 550 EUR	Feeder N:o	12	491 kVA	Feeder N:o	27	kVA
Switching time component of outage costs	142 216 EUR	Feeder N:o	13	3 609 kVA	Feeder N:o	28	kVA
Manual disconnector investment savings	126 000 EUR	Feeder N:o	14	1 706 kVA	Feeder N:o	29	kVA
Total cost of network over 40 years	2 987 671 EUR	Feeder N:o	15	2 739 kVA	Feeder N:o	30	kVA



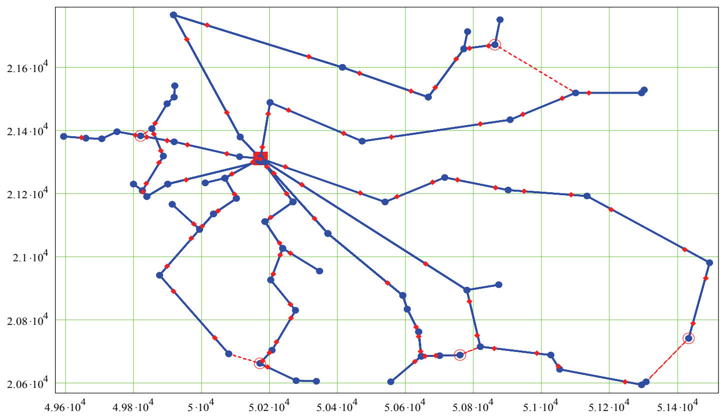
Reference area U12 fully looped 20 kV

Length of lines	17 207 m						
Length of reserve connections	1 891 m	Substation load		36 556 kVA			
Number of feeders	10	Feeder N:o	1	1 892 kVA	Feeder N:o	16	kVA
Number of remote disconnectors	0	Feeder N:o	2	3 192 kVA	Feeder N:o	17	kVA
Number of switching stations	0	Feeder N:o	3	5 495 kVA	Feeder N:o	18	kVA
		Feeder N:o	4	2 250 kVA	Feeder N:o	19	kVA
Looping ratio %	100 %	Feeder N:o	5	5 251 kVA	Feeder N:o	20	kVA
		Feeder N:o	6	4 870 kVA	Feeder N:o	21	kVA
Radial network cost	2 100 961 EUR	Feeder N:o	7	3 223 kVA	Feeder N:o	22	kVA
Full network cost	2 289 522 EUR	Feeder N:o	8	4 252 kVA	Feeder N:o	23	kVA
Reserve connections' cost	188 561 EUR	Feeder N:o	9	3 252 kVA	Feeder N:o	24	kVA
Conductor installed cost	722 018 EUR	Feeder N:o	10	2 878 kVA	Feeder N:o	25	kVA
Construction costs	1 001 981 EUR	Feeder N:o	11	kVA	Feeder N:o	26	kVA
Repair component of outage costs	0 EUR	Feeder N:o	12	kVA	Feeder N:o	27	kVA
Switching time component of outage costs	198 085 EUR	Feeder N:o	13	kVA	Feeder N:o	28	kVA
Manual disconnector investment savings	0 EUR	Feeder N:o	14	kVA	Feeder N:o	29	kVA
Total cost of network over 40 years	2 509 490 EUR	Feeder N:o	15	kVA	Feeder N:o	30	kVA



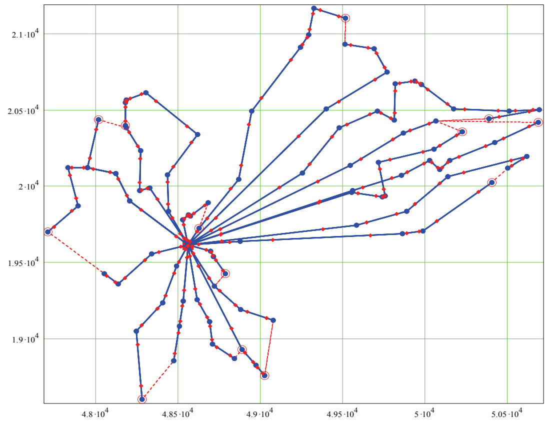
Reference area U12 optimally looped 20 kV

Length of lines	15 325 m						
Length of reserve connections	947 m	Substation load		36 556 kVA			
Number of feeders	9	Feeder N:o	1	5 313 kVA	Feeder N:o	16	kVA
Number of remote disconnectors	0	Feeder N:o	2	3 960 kVA	Feeder N:o	17	kVA
Number of switching stations	0	Feeder N:o	3	4 348 kVA	Feeder N:o	18	kVA
		Feeder N:o	4	3 310 kVA	Feeder N:o	19	kVA
Looping ratio %	72,9 %	Feeder N:o	5	4 831 kVA	Feeder N:o	20	kVA
		Feeder N:o	6	4 046 kVA	Feeder N:o	21	kVA
Radial network cost	1 879 528 EUR	Feeder N:o	7	4 390 kVA	Feeder N:o	22	kVA
Full network cost	1 972 049 EUR	Feeder N:o	8	3 509 kVA	Feeder N:o	23	kVA
Reserve connections' cost	92 522 EUR	Feeder N:o	9	2 849 kVA	Feeder N:o	24	kVA
Conductor installed cost	634 654 EUR	Feeder N:o	10	kVA	Feeder N:o	25	kVA
Construction costs	892 383 EUR	Feeder N:o	11	kVA	Feeder N:o	26	kVA
Repair component of outage costs	141 503 EUR	Feeder N:o	12	kVA	Feeder N:o	27	kVA
Switching time component of outage costs	185 568 EUR	Feeder N:o	13	kVA	Feeder N:o	28	kVA
Manual disconnector investment savings	159 000 EUR	Feeder N:o	14	kVA	Feeder N:o	29	kVA
Total cost of network over 40 years	2 152 879 EUR	Feeder N:o	15	kVA	Feeder N:o	30	kVA



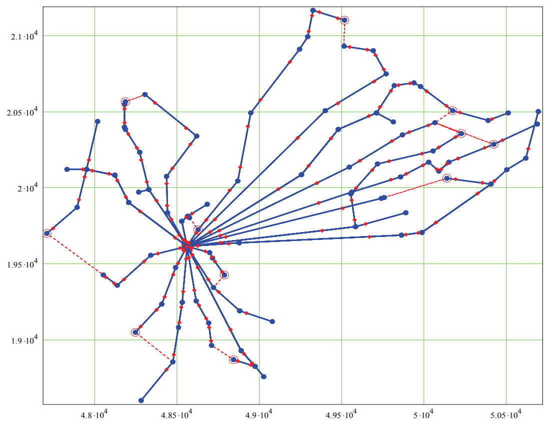
Reference area U13 fully looped 10 kV

Length of lines	38 799 m						
Length of reserve connections	4 364 m	Substation load		41 949 kVA			
Number of feeders	19	Feeder N:o	1	3 525 kVA	Feeder N:o	16	2 654 kVA
Number of remote disconnectors	0	Feeder N:o	2	671 kVA	Feeder N:o	17	2 874 kVA
Number of switching stations	0	Feeder N:o	3	2 092 kVA	Feeder N:o	18	1 527 kVA
		Feeder N:o	4	2 745 kVA	Feeder N:o	19	1 781 kVA
Looping ratio %	100 %	Feeder N:o	5	3 586 kVA	Feeder N:o	20	kVA
		Feeder N:o	6	2 091 kVA	Feeder N:o	21	kVA
Radial network cost	4 842 491 EUR	Feeder N:o	7	2 169 kVA	Feeder N:o	22	kVA
Full network cost	5 285 040 EUR	Feeder N:o	8	2 247 kVA	Feeder N:o	23	kVA
Reserve connections' cost	442 549 EUR	Feeder N:o	9	1 489 kVA	Feeder N:o	24	kVA
Conductor installed cost	1 636 970 EUR	Feeder N:o	10	3 058 kVA	Feeder N:o	25	kVA
Construction costs	2 259 239 EUR	Feeder N:o	11	2 559 kVA	Feeder N:o	26	kVA
Repair component of outage costs	0 EUR	Feeder N:o	12	2 270 kVA	Feeder N:o	27	kVA
Switching time component of outage costs	267 894 EUR	Feeder N:o	13	1 453 kVA	Feeder N:o	28	kVA
Manual disconnector investment savings	0 EUR	Feeder N:o	14	1 810 kVA	Feeder N:o	29	kVA
Total cost of network over 40 years	5 575 816 EUR	Feeder N:o	15	1 347 kVA	Feeder N:o	30	kVA



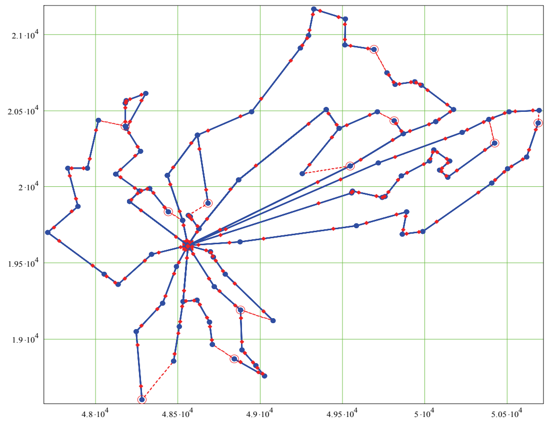
Reference area U13 optimally looped 10 kV

Length of lines	37 850 m						
Length of reserve connections	3 516 m	Substation load		41 949 kVA			
Number of feeders	19	Feeder N:o	1	3 525 kVA	Feeder N:o	16	2 654 kVA
Number of remote disconnectors	0	Feeder N:o	2	671 kVA	Feeder N:o	17	2 434 kVA
Number of switching stations	0	Feeder N:o	3	621 kVA	Feeder N:o	18	1 420 kVA
		Feeder N:o	4	3 160 kVA	Feeder N:o	19	1 781 kVA
Looping ratio %	82,8 %	Feeder N:o	5	3 229 kVA	Feeder N:o	20	kVA
		Feeder N:o	6	2 091 kVA	Feeder N:o	21	kVA
Radial network cost	4 727 110 EUR	Feeder N:o	7	2 277 kVA	Feeder N:o	22	kVA
Full network cost	5 083 683 EUR	Feeder N:o	8	3 660 kVA	Feeder N:o	23	kVA
Reserve connections' cost	356 573 EUR	Feeder N:o	9	1 489 kVA	Feeder N:o	24	kVA
Conductor installed cost	1 559 388 EUR	Feeder N:o	10	1 745 kVA	Feeder N:o	25	kVA
Construction costs	2 203 988 EUR	Feeder N:o	11	2 559 kVA	Feeder N:o	26	kVA
Repair component of outage costs	254 584 EUR	Feeder N:o	12	2 270 kVA	Feeder N:o	27	kVA
Switching time component of outage costs	244 694 EUR	Feeder N:o	13	1 894 kVA	Feeder N:o	28	kVA
Manual disconnector investment savings	126 000 EUR	Feeder N:o	14	1 810 kVA	Feeder N:o	29	kVA
Total cost of network over 40 years	5 475 160 EUR	Feeder N:o	15	2 660 kVA	Feeder N:o	30	kVA



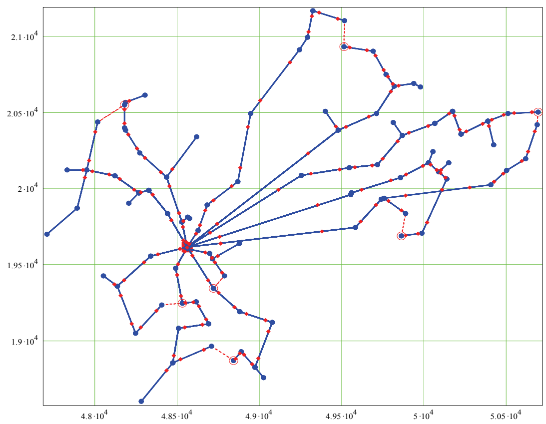
Reference area U13 fully looped 20 kV

Length of lines	32 590 m						
Length of reserve connections	2 729 m	Substation load		41 949 kVA			
Number of feeders	12	Feeder N:o	1	2 378 kVA	Feeder N:o	16	kVA
Number of remote disconnectors	0	Feeder N:o	2	3 433 kVA	Feeder N:o	17	kVA
Number of switching stations	0	Feeder N:o	3	4 900 kVA	Feeder N:o	18	kVA
		Feeder N:o	4	4 633 kVA	Feeder N:o	19	kVA
Looping ratio %	100 %	Feeder N:o	5	3 225 kVA	Feeder N:o	20	kVA
		Feeder N:o	6	3 099 kVA	Feeder N:o	21	kVA
Radial network cost	3 748 569 EUR	Feeder N:o	7	2 694 kVA	Feeder N:o	22	kVA
Full network cost	4 011 482 EUR	Feeder N:o	8	2 873 kVA	Feeder N:o	23	kVA
Reserve connections' cost	262 914 EUR	Feeder N:o	9	4 016 kVA	Feeder N:o	24	kVA
Conductor installed cost	1 353 196 EUR	Feeder N:o	10	4 570 kVA	Feeder N:o	25	kVA
Construction costs	1 897 739 EUR	Feeder N:o	11	2 874 kVA	Feeder N:o	26	kVA
Repair component of outage costs	0 EUR	Feeder N:o	12	3 253 kVA	Feeder N:o	27	kVA
Switching time component of outage costs	384 975 EUR	Feeder N:o	13	kVA	Feeder N:o	28	kVA
Manual disconnector investment savings	0 EUR	Feeder N:o	14	kVA	Feeder N:o	29	kVA
Total cost of network over 40 years	4 428 720 EUR	Feeder N:o	15	kVA	Feeder N:o	30	kVA



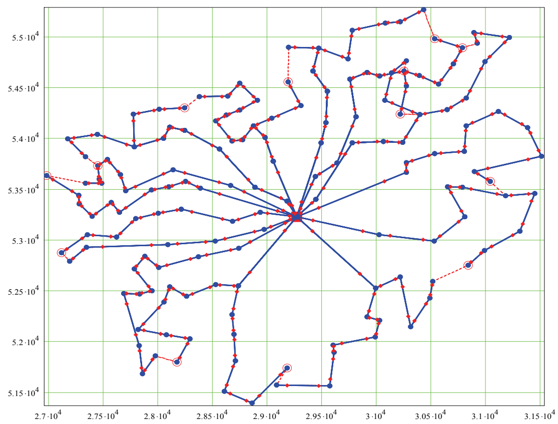
Reference area U13 optimally looped 20 kV

Length of lines	28 887 m						
Length of reserve connections	1 406 m	Substation load		41 949 kVA			
Number of feeders	11	Feeder N:o	1	3 727 kVA	Feeder N:o	16	kVA
Number of remote disconnectors	0	Feeder N:o	2	5 076 kVA	Feeder N:o	17	kVA
Number of switching stations	0	Feeder N:o	3	4 830 kVA	Feeder N:o	18	kVA
		Feeder N:o	4	3 112 kVA	Feeder N:o	19	kVA
Looping ratio %	78,5 %	Feeder N:o	5	3 766 kVA	Feeder N:o	20	kVA
		Feeder N:o	6	3 448 kVA	Feeder N:o	21	kVA
Radial network cost	3 348 570 EUR	Feeder N:o	7	3 103 kVA	Feeder N:o	22	kVA
Full network cost	3 484 053 EUR	Feeder N:o	8	3 085 kVA	Feeder N:o	23	kVA
Reserve connections' cost	135 483 EUR	Feeder N:o	9	4 588 kVA	Feeder N:o	24	kVA
Conductor installed cost	1 190 798 EUR	Feeder N:o	10	3 678 kVA	Feeder N:o	25	kVA
Construction costs	1 682 071 EUR	Feeder N:o	11	3 535 kVA	Feeder N:o	26	kVA
Repair component of outage costs	148 778 EUR	Feeder N:o	12	kVA	Feeder N:o	27	kVA
Switching time component of outage costs	348 256 EUR	Feeder N:o	13	kVA	Feeder N:o	28	kVA
Manual disconnector investment savings	135 000 EUR	Feeder N:o	14	kVA	Feeder N:o	29	kVA
Total cost of network over 40 years	3 865 749 EUR	Feeder N:o	15	kVA	Feeder N:o	30	kVA



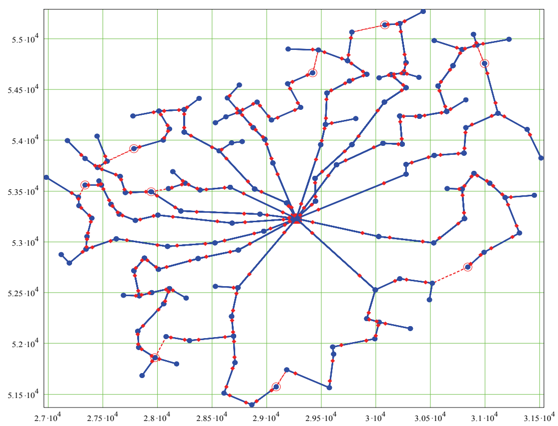
Reference area U15 fully looped 20 kV

Length of lines	66 494 m						
Length of reserve connections	4 002 m	Substation load		48 487 kVA			
Number of feeders	14	Feeder N:o	1	2 411 kVA	Feeder N:o	16	kVA
Number of remote disconnectors	0	Feeder N:o	2	3 700 kVA	Feeder N:o	17	kVA
Number of switching stations	0	Feeder N:o	3	1 699 kVA	Feeder N:o	18	kVA
		Feeder N:o	4	3 456 kVA	Feeder N:o	19	kVA
Looping ratio %	100 %	Feeder N:o	5	4 875 kVA	Feeder N:o	20	kVA
		Feeder N:o	6	4 155 kVA	Feeder N:o	21	kVA
Radial network cost	5 444 390 EUR	Feeder N:o	7	4 553 kVA	Feeder N:o	22	kVA
Full network cost	5 717 521 EUR	Feeder N:o	8	3 548 kVA	Feeder N:o	23	kVA
Reserve connections' cost	273 131 EUR	Feeder N:o	9	3 535 kVA	Feeder N:o	24	kVA
Conductor installed cost	2 723 894 EUR	Feeder N:o	10	2 907 kVA	Feeder N:o	25	kVA
Construction costs	2 067 969 EUR	Feeder N:o	11	3 794 kVA	Feeder N:o	26	kVA
Repair component of outage costs	0 EUR	Feeder N:o	12	3 572 kVA	Feeder N:o	27	kVA
Switching time component of outage costs	795 676 EUR	Feeder N:o	13	3 324 kVA	Feeder N:o	28	kVA
Manual disconnector investment savings	0 EUR	Feeder N:o	14	2 958 kVA	Feeder N:o	29	kVA
Total cost of network over 40 years	6 567 294 EUR	Feeder N:o	15	kVA	Feeder N:o	30	kVA



Reference area U15 optimally looped 20 kV

Length of lines	62 009 m						
Length of reserve connections	2 970 m	Substation load		48 487 kVA			
Number of feeders	14	Feeder N:o	1	4 789 kVA	Feeder N:o	16	kVA
Number of remote disconnectors	0	Feeder N:o	2	3 324 kVA	Feeder N:o	17	kVA
Number of switching stations	0	Feeder N:o	3	3 506 kVA	Feeder N:o	18	kVA
		Feeder N:o	4	3 953 kVA	Feeder N:o	19	kVA
Looping ratio %	77,1 %	Feeder N:o	5	4 953 kVA	Feeder N:o	20	kVA
		Feeder N:o	6	3 179 kVA	Feeder N:o	21	kVA
Radial network cost	5 071 781 EUR	Feeder N:o	7	1 456 kVA	Feeder N:o	22	kVA
Full network cost	5 270 575 EUR	Feeder N:o	8	3 202 kVA	Feeder N:o	23	kVA
Reserve connections' cost	198 794 EUR	Feeder N:o	9	3 190 kVA	Feeder N:o	24	kVA
Conductor installed cost	2 490 292 EUR	Feeder N:o	10	3 106 kVA	Feeder N:o	25	kVA
Construction costs	1 928 488 EUR	Feeder N:o	11	3 532 kVA	Feeder N:o	26	kVA
Repair component of outage costs	262 816 EUR	Feeder N:o	12	3 394 kVA	Feeder N:o	27	kVA
Switching time component of outage costs	728 275 EUR	Feeder N:o	13	3 406 kVA	Feeder N:o	28	kVA
Manual disconnector investment savings	165 000 EUR	Feeder N:o	14	3 497 kVA	Feeder N:o	29	kVA
Total cost of network over 40 years	6 134 041 EUR	Feeder N:o	15	kVA	Feeder N:o	30	kVA



Comparison: Model networks / VOH-algorithm / Real networks (MV feeder system only) 1/2

U11 Urban core	20 kV optimally looped	20 kV fully looped	20 kV model fully looped	10 kV optimally looped	10 kV fully looped	10 kV real fully looped
Area km^2	1,26	1,26	1,26	1,26	1,26	1,26
Number of TS	117	117	117	117	117	121
DBTS / km	0,104	0,104	0,104	0,104	0,104	0,102
$LLAF_{MV}$	1,41	1,41	1,41	1,41	1,41	
Number of MV Lines	13	13	15	22	25	42
LL_{MV} Looped	16,6	18,5	18,3	23,3	25,3	49,0
Volume (line length) 10 kV vs 20 kV				140 %	137 %	
Unadjusted ratios	90 %	**100 %**	99 %	92 %	**100 %**	194 %
Actual line length factor				1,55	1,55	
Correction factor 1				1,10	1,10	
Vertical extra line length per cable end / km				0,01	0,01	
Adjusted DBTS / km				0,124	0,124	
Correction factor 2				1,19	1,19	
Number of TS (modelled/real): correction factor 3						0,97
Reduction of direct reserve lines between substations / km						-3,0
Reduction of subway feeders / km						-1,0
Adjusted line length / km				30,5	33,1	43,4
Adjusted ratios				92 %	**100 %**	131 %

U12 Urban industrial	20 kV optimally looped	20 kV fully looped	20 kV model fully looped	10 kV optimally looped	10 kV fully looped	10 kV real fully looped
Area km^2	2,43	2,43	2,43	2,43	2,43	2,43
Number of TS	69	69	69	69	69	79
DBTS / km	0,188	0,188	0,188	0,188	0,188	0,175
$LLAF_{MV}$	1,41	1,41	1,41	1,41	1,41	
Number of MV Lines	8	10	10	15	16	34
LL_{MV} Looped	16,3	19,1	19,6	21,6	24,5	46,1
Volume (line length) 10 kV vs 20 kV				133 %	128 %	
Unadjusted ratios	85 %	**100 %**	103 %	88 %	**100 %**	188 %
Actual line length factor				1,41	1,41	
Correction factor 1				1,00	1,00	
Vertical extra line length per cable end / km				0,01	0,01	
Adjusted DBTS / km				0,208	0,208	
Correction factor 2				1,11	1,11	
Number of TS (modelled/real): correction factor 3						0,87
Reduction of direct reserve lines between substations / km						-3,0
Reduction of subway feeders / km						0,0
Adjusted line length / km				23,8	27,0	37,3
Adjusted ratios				88 %	**100 %**	138 %

Comparison: Model networks / VOH-algorithm / Real networks (MV feeder system only) 2/2

U13 Urban mixed	20 kV optimally looped	20 kV fully looped	20 kV model fully looped	10 kV optimally looped	10 kV fully looped	10 kV real fully looped
Area km^2	4,15	4,15	4,15	4,15	4,15	4,15
Number of TS	86	86	86	86	86	99
DBTS / km	0,220	0,220	0,220	0,220	0,220	0,205
$LLAF_{MV}$	1,41	1,41	1,41	1,41	1,41	
Number of MV Lines	11	14	14	18	19	29
LL_{MV} Looped	30,3	35,3	28,9	41,4	43,2	57,5
Volume (line length) 10 kV vs 20 kV				137 %	122 %	
Unadjusted ratios	86 %	**100 %**	82 %	96 %	**100 %**	133 %
Actual line length factor				1,41	1,41	
Correction factor 1				1,00	1,00	
Vertical extra line length per cable end / km				0,01	0,01	
Adjusted DBTS / km				0,240	0,240	
Correction factor 2				1,09	1,09	
Number of TS (modelled/real): correction factor 3						0,87
Reduction of direct reserve lines between substations / km						-3,0
Reduction of subway feeders / km						0,0
Adjusted line length / km				45,0	47,0	46,9
Adjusted ratios				96 %	**100 %**	100 %

U15 Suburban SH - mixed	20 kV optimally looped	20 kV fully looped	20 kV real fully looped
Area km^2	13,32	13,32	13,32
Number of TS	154	154	167
DBTS / km	0,294	0,294	0,282
$LLAF_{MV}$	1,41	1,41	1,41
Number of MV Lines	11	12	35
LL_{MV} Looped	65,0	70,5	118,0
Unadjusted ratios	92 %	**100 %**	167 %
Actual line length factor	1,41	1,41	
Correction factor 1	1,00	1,00	
Vertical extra line length per cable end / km	0,01	0,01	
Adjusted DBTS / km	0,314	0,314	
Correction factor 2	1,07	1,07	
Number of TS (modelled/real): correction factor 3			0,92
Reduction of direct reserve lines between substations / km			-10,0
Reduction of subway feeders / km			0,0
Adjusted line length / km	69,2	75,1	98,8
Adjusted ratios	92 %	**100 %**	132 %

1. List of symbols and acronyms

Legend of diagrams

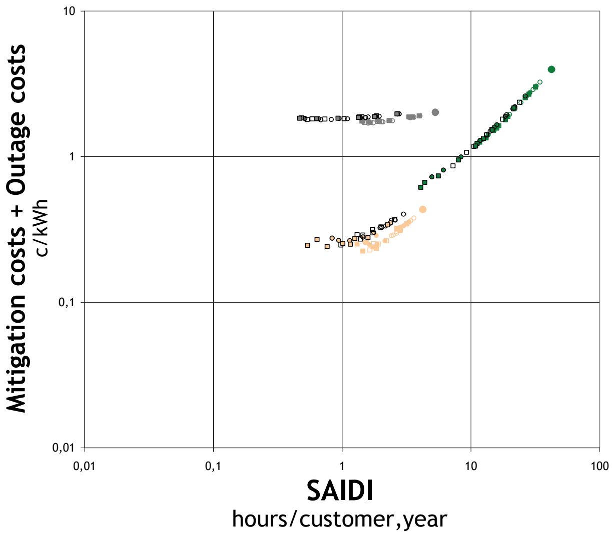
- Rural OHL in forest - REF
- Rural OHL in forest - SECT
- Rural OHL in forest - REM SECT
- Rural OHL in forest - CBS + SECT
- Rural OHL in forest - CBS + REM SECT
- Rural OHL in forest - SECT + RES
- Rural OHL in forest - REM SECT + RES
- Rural OHL in forest - CBS + SECT + RES
- Rural OHL in forest - CBS + REM SECT + RES
- Rural OHL in forest - REF
- Rural OHL in open field - SECT
- Rural OHL in open field - REM SECT
- Rural OHL in open field - CBS + SECT
- Rural OHL in open field - CBS + REM SECT
- Rural OHL in open field - SECT + RES
- Rural OHL in open field - REM SECT + RES
- Rural OHL in open field - CBS + SECT + RES
- Rural OHL in open field - CBS + REM SECT + RES
- Rural cable - REF
- Rural cable - SECT
- Rural cable - REM SECT
- Rural cable - CBS + SECT
- Rural cable - CBS + REM SECT
- Rural cable - SECT + RES
- Rural cable - REM SECT + RES
- Rural cable - CBS + SECT + RES
- Rural cable - CBS + REM SECT + RES

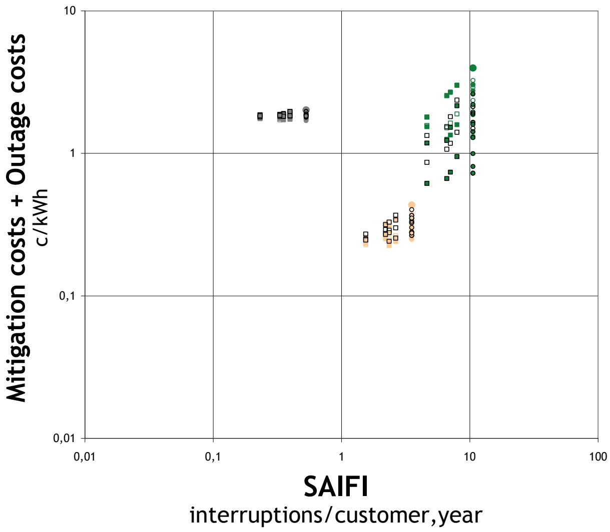
- Urban fully looped cable - REF
- Urban fully looped cable - REM SECT
- Urban fully looped cable - EF COMP
- Urban fully looped cable - REM FAULT IND

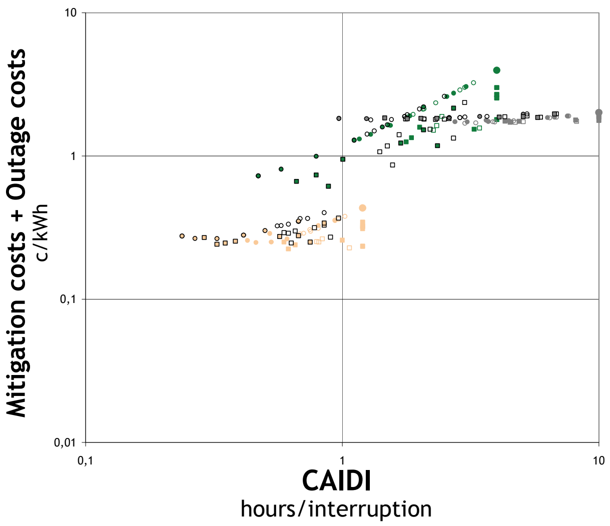
Acronyms

REF	Reference point for a feeder, a feeder without any mitigation actions
SECT	Manually operated sectionalizers
REM SECT	Remotely operated sectionalizers
CBS	Intermediate circuit breakers along the feeder
RES	Reserve connections
EF COMP	Earth fault current compensation
REM FAULT IND	Remotely read fault indicators

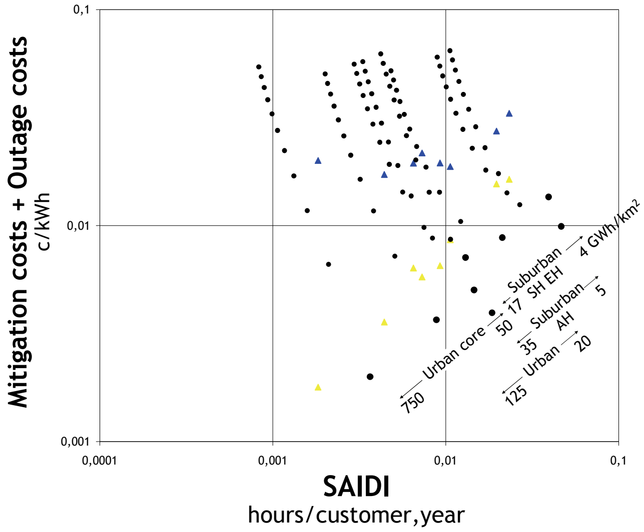
2. A rural feeder example (ED=0,14 GWh/km^2,year)

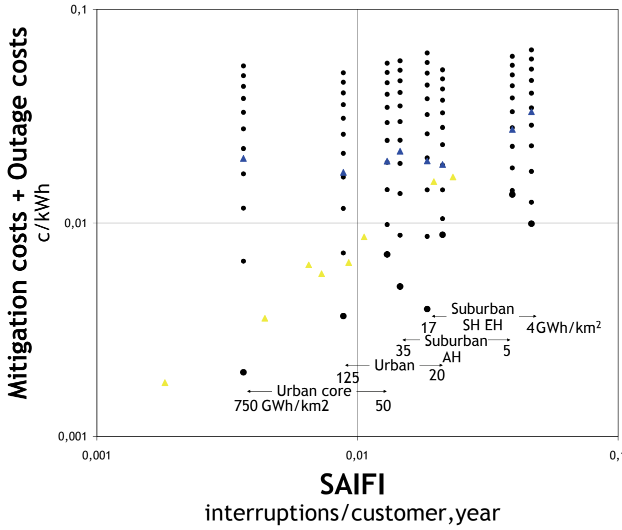


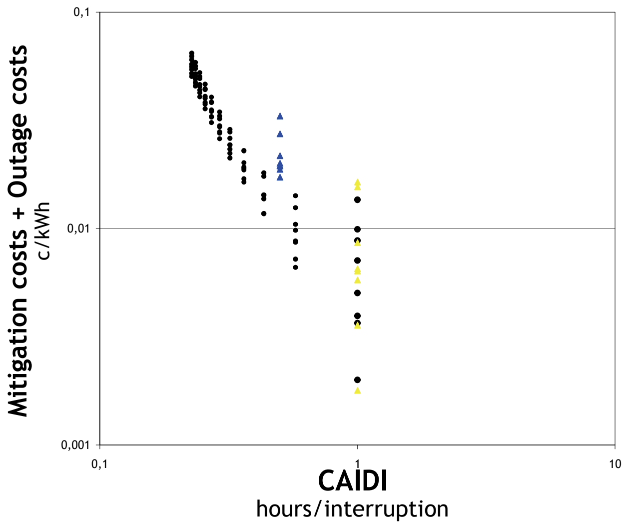




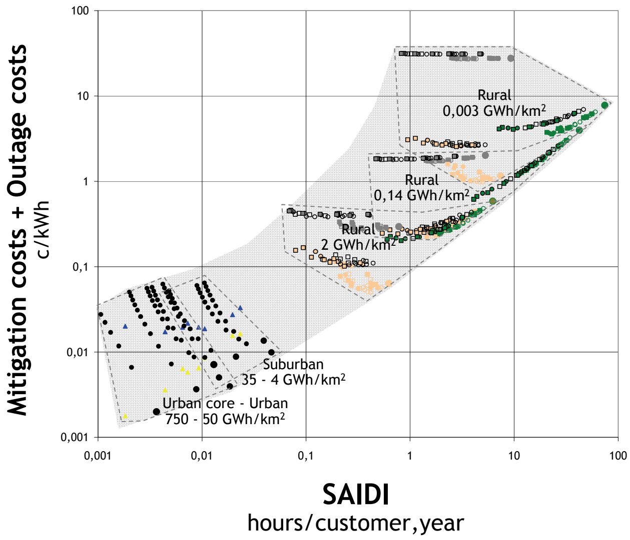
3. Reliability indices for urban feeders

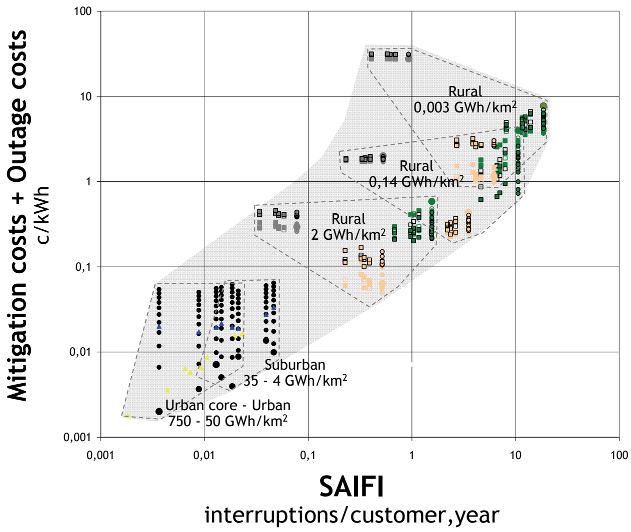


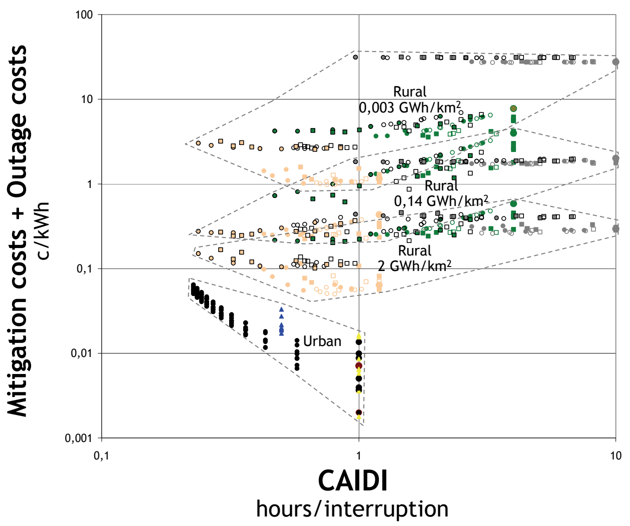




4. Summary of the reliability indices







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